

BEFORE THE
CALIFORNIA ENERGY COMMISSION (CEC)

In the matter of,)	
)	Docket No. 13-IEP-1M
2013 Integrated Energy)	
Policy Report)	Workshop Re:
(2013 IEPR))	Biomethane
_____)	Procurement Challenges

Challenges to Procuring Biomethane in California

California Energy Commission
Hearing Room A
1516 Ninth Street
Sacramento, California

Friday, May 31, 2013
9:00 A.M.

Reported by:
Kent Odell

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1 P R O C E E D I N G S

2 MAY 31, 2013

9:04 A.M.

3 MS. SALAZAR: Okay, I think we're going
4 to get started here in a bit. Good morning,
5 everyone and thank you for coming to the Energy
6 Commission's 2013 Staff IEPR Workshop on
7 Biomethane Procurement in California.

8 Before we get started, I just wanted to
9 go ahead and cover some housekeeping rules. For
10 those of you that are unfamiliar with building,
11 we have bathrooms located just outside the
12 double doors and over to the left; there is a
13 snack bar on the second floor located just under
14 the white awning; and finally, if we have an
15 emergency and we have to evacuate the building,
16 please proceed quickly and calmly following our
17 staff to the park located diagonally across the
18 street, and we'll reconvene there until they
19 give us the all clear sign.

20 My name is Rachel Salazar. I work in
21 the Renewable Energy Office here at the Energy
22 Commission. And I just wanted to let folks know
23 that we are being recorded. This is being
24 broadcast over WebEx, so make sure that you
25 realize that we are being recorded.

1 Just to give you a quick overview of the
2 purpose of this workshop, we are here today to
3 talk about the AB 1900 requirements. The Energy
4 Commission's role in the AB 1900 is to assess
5 the challenges and potential solutions to
6 biomethane procurement here in California.
7 We're asking stakeholders today to identify some
8 of the challenges that limit the procurement,
9 and also if you have some recommendations for
10 solutions or ideas on what we can do to overcome
11 these challenges, or any additional actions the
12 State can take, and any other comments.

13 Today we're going to be hearing from
14 Paul Milkey with the ARB and he is going to be
15 providing a summary of the recommendations that
16 they sent jointly with OEHHA to the CPUC.

17 And following Paul, we have Jennifer
18 Kalafut from the CPUC; she is Advisor to
19 Commissioner Peterman and she is going to be
20 providing us with a very brief update on their
21 proceeding of AB 1900.

22 All of the materials for today's
23 workshop can be found at this website, it's our
24 2013 IEPR website.

25 Quickly, some of the policy drivers for

1 this. As you know, the Energy Commission has
2 been directed to hold public hearings to
3 identify impediments that limit procurement of
4 biomethane in California, and this is including
5 but not limited to the interconnection
6 impediments. And we will be providing an
7 overview and some recommendations in the 2013
8 IEPR, as well.

9 Additionally, the 33 percent RPS derived
10 from either landfill gas or digester gas is
11 eligible, provided it meets the requirements in
12 the 7th Edition of the RPS Guidebook.

13 And then of course, we have the Low
14 Carbon Fuel Standard, which calls for at least a
15 10 percent reduction in carbon intensity from
16 in-state transportation fuels by 2020. And then
17 the AB 32 Scoping Plan, which was updated in
18 2013, and biogas and biomethane were both
19 identified as something that can play a role in
20 four of the six focus areas listed here.

21 We are going to be taking written
22 comments and they are due by June 14th by 5:00
23 p.m. Just a reminder to include both the Docket
24 Number and the title, Biomethane Procurement
25 Challenges in the subject line of your email,

1 and you can email that to docket@energy.ca.gov
2 and please also copy our Technical Lead staff,
3 Garry O'Neill Mariscal.

4 And so with that, I'm going to hand it
5 over to Paul Milkey.

6 MR. MILKEY: Well, thank you for having
7 me here today to provide an opportunity to talk
8 about the work that the Air Resources Board of
9 the Office of Environmental Health Hazard
10 Assessment have done under AB 1900. And again,
11 I'm here with the Air Resources Board, but it's
12 been very much a joint effort with both of these
13 agencies.

14 So this is an overview of the
15 presentation. We wanted to cover a little bit
16 of background quickly, then cover some of the
17 highlights of the process that we used to
18 develop the recommendations to the California
19 Public Utilities Commission.

20 So a little bit about AB 1900. AB 1900
21 requires the CPUC to adopt standards by the end
22 of this year that both, 1) protect public
23 health, and 2) ensure pipeline integrity and
24 safety. It's important this effort the ARB and
25 OEHHA develop recommendations for health based

1 standards for constituents of concern in
2 biogas. And we did not cover the pipeline
3 integrity issues at all.

4 As specified in AB 1900, the ARB was to
5 propose health based standards by May 15th of
6 this year in consultation with the other State
7 agencies listed on this slide. And we did meet
8 this deadline and posted our report on May 15th.

9 In developing these standards, we
10 worked closely with OEHHA staff, which is the
11 lead agency for a number of the tasks that were
12 necessary to complete this work.

13 And under AB 1900, the California PUC
14 is to give due deference to the ARB Public
15 Health Recommendations in adopting their
16 standards by the end of this year.

17 So this provides a little bit of a
18 breakdown of the tasks that both the ARB and
19 OEHHA had, and what I'll be doing is I'll be
20 going through each of these sort of covering the
21 highlights in the presentation here. Oh, also
22 one other thing I should mention, the Bill
23 requires updates to the recommendations, at most
24 every five years, and we do anticipate a few
25 areas where we want to do some further

1 investigation. For example, one of those areas
2 is we want to look at anaerobic digesters that
3 use food waste or green waste as the feedstock.
4 In doing the work we focused on the primary
5 sources of biogas, but this is one that we'll
6 probably be taking another look at.

7 So as I just mentioned, the focus has
8 been on the larger sources of biogas, so we're
9 talking about landfills, dairies, and sewage
10 treatment plants, and we're referring to those
11 as POTWs. And we believe these are the sources
12 at this moment with the greatest potential to
13 economically inject into the natural gas
14 pipeline, in other words, they have the volume
15 of gas necessary.

16 Staff analyzed the constituents in both
17 raw, that is untreated biogas, to determine the
18 compounds in biogas that need to be controlled,
19 as well as the treated biogas, which I'll refer
20 to as biomethane, to determine the potential for
21 the control technologies to limit constituents
22 of concern.

23 The primary focus of the work was on
24 exposure to direct emissions and so what we
25 didn't do is look at things like combustion

1 products of the gas, for example, when you're
2 using a cook top, for example. For this,
3 there's little information available on the
4 combustion products and AB 1900 does direct
5 staff to use available sources of information.

6 So staff, I believe we've done a
7 thorough analysis of the potential constituents
8 of concern, but we can address additional
9 compounds or new sources of biogas or other
10 topics in these updates that I mentioned.

11 Based on our review of the data, we
12 identified about 270 trace chemicals, or
13 chemical groups, in biogas. OEHHA determined
14 that many of these are most likely biologic or
15 chemical degradation products of biological
16 materials. And the last bullet here lists the
17 primary sources of data that we used in
18 developing this list of constituents, and of
19 these the Gas Technology Institute Reports, or
20 GTI Reports, were the most comprehensive and the
21 most useful for this effort.

22 So as noted earlier, OEHHA was tasked
23 with determining health protective values for
24 constituents of concern in biogas. And this
25 slide shows the four main sources of toxicity

1 data and risk values that they used in there
2 valuations. Using these sources, they were able
3 to identify risk-screening values, the health
4 values, for about 180 compounds, and they used
5 surrogate screening values for another 25
6 compounds or chemical groups.

7 So sort of the next part of the process
8 was looking at exposure scenarios, so the bill
9 required ARB to identify realistic exposure
10 scenarios in evaluating the risk, and then our
11 valuation, we came up with four different
12 scenarios, two for a residential end user and
13 two for a worker scenario.

14 So the first residential scenario is a
15 leak scenario where you have a residence with a
16 small constant leak; the second is a stovetop
17 scenario where a resident is exposed to the gas
18 for the pre-ignition phase where you turn on the
19 burner, the gas comes out, and there's a few
20 seconds before it actually lights up. So for
21 the worker scenario, the first worker scenario
22 we looked at was at a biogas or biomethane
23 production facility where there may be a small
24 constant leak in the process unit equipment, so
25 this is very similar to the residential, except

1 it's in a commercial setting where you have this
2 slow constant leak.

3 The second worker scenario is for a
4 utility worker making service calls where a
5 customer is experiencing a leak in the home.

6 And in our analysis we looked at 13
7 sets of data, three for natural gas, four for
8 landfill derived biogas, four for POTWs, and two
9 for dairy. We looked at both raw and treated
10 biogas in looking at these datasets. And the
11 reported concentration data was evaluated for
12 compounds individually, as well as holistically
13 where we looked at the risks from all the
14 compounds in each of these sets of data.

15 And in our valuation, we used
16 conservative assumptions, one of those being
17 that we assumed that a concentration of 100
18 percent biogas would enter the home or business
19 and same with natural gas.

20 These are the criteria we used in
21 identifying a constituent of concern from the
22 many trace compounds that we talked about
23 earlier. For a residential setting, we used a
24 hazard quotient of .01, and this would be for
25 chronic or acute risks; and for cancer, we used

1 a threshold of one chance in a million. For
2 workers, the criterion is different, and this is
3 standard practice, you're talking about healthy
4 adults and fewer hours of exposure, so that
5 reflects higher numbers for the worker
6 thresholds.

7 So in using this process, we came up
8 with 12 constituents of concern that were
9 identified from the process. Five of the
10 constituents were identified based on their
11 carcinogenicity and the remaining compounds
12 based on a chronic non-cancer hazard quotient.

13 This table shows the biogas source for
14 each of the constituents of concern that were
15 found, so as you can see all 12 of the
16 constituents of concern were found in landfills,
17 six of them were found in POTWs, and five in
18 dairy biogas.

19 And this shows the OEHHA recommended
20 health protective values for the 12 constituents
21 of concern that we just talked about, and I
22 won't go over those.

23 So now that we have our constituents,
24 we need a risk management approach. So in
25 crafting the approach, we relied on a couple of

1 things, first, the OEHHA health protective
2 levels that I just showed you, and then we
3 relied on Risk Management Guidelines approved by
4 the Air Resources Board in 1993. And these
5 guidelines continue to be used by the Air
6 Resources Board and local Air Districts when
7 making risk management decisions about sources
8 of toxic air contaminants.

9 The Guidelines identified trigger
10 levels and lower and upper action levels for
11 potential cancer risk, and total non-cancer
12 hazard indices to be considered when approving a
13 permit in California. The Risk Management
14 Guidelines reflect the uncertainty and
15 variability in risk assessments and provide
16 public health protection.

17 So this table summarizes our
18 recommended risk management approach. It uses
19 the OEHHA health protective levels as the
20 trigger levels for requiring more frequent
21 monitoring of constituents of concern. So if an
22 individual constituent of concern was determined
23 to be below the trigger level in biomethane,
24 then only annual testing would be required for
25 that compound. If, however, the compound was

1 found to be present in biomethane at a
2 concentration above the trigger level, either,
3 that is, above a cancer risk of one in a
4 million, or a hazard quotient greater than .1,
5 then that constituent would be subject to
6 quarterly monitoring. Upon each quarterly
7 monitoring event, the operator is to determine
8 the total potential cancer risk and hazard index
9 for all the constituents that are subject to
10 this more frequent monitoring, that is the
11 quarterly monitoring.

12 If the total risk level collectively
13 exceeds the lower actual level, three times in a
14 12-month period, then the facility would be shut
15 down and typically the gas would be diverted to
16 a flare. And then the operator would then need
17 to determine how they're going to bring their
18 measured levels in biomethane down, so they
19 would have to address the upgrading equipment at
20 the plant.

21 If at any time the potential cancer
22 risk or hazard index for the constituents of
23 concern exceeds the upper action level, then the
24 facility would shut down their flow to the
25 pipeline. And again, they would have to address

1 what's going on with the system and work on the
2 upgrading equipment.

3 So based on the available data,
4 biomethane can be safely injected into the
5 pipeline. Most all of the constituents of
6 concern were found to be below the trigger level
7 and all of them were below the lower action
8 level, so injection of biomethane does not
9 present an additional risk as compared to
10 natural gas.

11 So under the recommended risk
12 management approach, the constituents of concern
13 would be monitored depending on the source of
14 the biogas. So we talked about earlier
15 landfills had all 12 of the constituents, and
16 the other sources had fewer, so you're going to
17 have to do more testing if it's landfill biogas,
18 for example, compared to dairy or sewage
19 treatment biogas.

20 Okay, so when you're starting up a
21 brand new biogas biomethane facility for the
22 first time, things are a little bit different,
23 and this is our recommendation for this sort of
24 pre-injection start-up testing.

25 Under this approach, you would test two

1 times for the relevant constituents of concern
2 over a two to four-week period. The approach
3 would also require that the utility and the
4 biomethane producer agree on a procedure to
5 ensure that the gas treatment system is
6 continuously operated as designed to control
7 constituents of concern. And one option for
8 doing this might be to see if the tariff
9 requirements for natural gas are being met.

10 And during this pre-injection start-up
11 phase, all of the constituents of concern would
12 need to be below the lower action level in order
13 to begin injection into the pipeline, so that's
14 a little bit different. To get it started, we
15 want to make sure you're sort of starting off on
16 the right foot.

17 So once you've begun injection, you're
18 subject to periodic testing requirements, and
19 this is a little bit of a repeat, but if
20 constituents of concern are not detected at all,
21 or they are below the trigger level, then you're
22 subject to annual monitoring, so that's kind of
23 what we said before. Now, if you're above that
24 level, then it's different, then it's going to
25 be more frequent. So for constituents of

1 concern that are above that trigger level, then
2 it's quarterly testing that's going to be
3 required. And if an individual constituent of
4 concern is found to be below the trigger level
5 four consecutive times after that, then it can
6 revert back to the annual testing.

7 One of the things that's different
8 about this quarterly testing is you're going to
9 test the whole group of compounds that you're
10 testing more frequently and you're going to get
11 a combined risk and take a look at it and
12 compare it to the lower action level and the
13 upper action level. So if the combined cancer
14 risk exceeds the upper action level, or the
15 lower action level three times in a 12-month
16 period, then you will be shut off to the
17 pipeline.

18 On the other hand, if four consecutive
19 quarterly tests of the group demonstrates that
20 the total risk is below the lower action level,
21 then the compounds can go back to annual
22 testing.

23 So under this approach where you need
24 to evaluate the collective risks, ARB is
25 planning to provide a Web-based tool that can

1 calculate the risks for you, so that you don't
2 have to do that.

3 And here is a flowchart that kind of
4 shows the whole process which hopefully will
5 make things clearer, I know I've had a few
6 slides on it and, I don't know, maybe you got a
7 little lost, but hopefully this will help a
8 little bit. So I'll go through it sort of one
9 more time.

10 So basically this summarizes the
11 testing, and the LAL is Lower Action Level; UAL
12 is Upper Action Level. So individual compounds
13 below the trigger level go to annual testing.
14 Compounds above the trigger level will require
15 quarterly testing. Their collective risk will
16 be monitored and compared to the Lower Action
17 Level and the Upper Action Level. If the
18 collective risk is below the Lower Action Level
19 for four consecutive quarterly tests, then the
20 group can go to annual testing. If it's above
21 the Lower Action Level three times in a 12-month
22 period, then the supply to the pipeline must be
23 shut off. If it is above the upper action level
24 once, the supply must be shut off. And note
25 that the flow chart shows sort of on the left,

1 that arrow on the far left down at the bottom,
2 shows that for pre-injection start-up testing,
3 injection cannot begin if the collective risk is
4 above the lower action level. So hopefully that
5 helped a little bit.

6 We also had some recommendations for
7 Recordkeeping and Reporting. We're recommending
8 that records of testing be retained for a
9 minimum of three years by the testing entity,
10 whoever that is; an annual report be provided to
11 the California Public Utilities Commission,
12 which the CPUC would provide to ARB and OEHHA,
13 and this annual report would include all test
14 data, annual biomethane production, monitoring
15 perimeters used to ensure that the biogas
16 upgrading or conditioning system is working
17 effectively, and a record of any shutoff events,
18 the reason for the shutoff, and corrective
19 actions taken.

20 Now, if the utility is performing the
21 required health based testing, then they would
22 report the test results within two weeks, or 24
23 hours for a shutoff event, to the biomethane
24 producer. And sort of looking at it the other
25 way, if it's the biomethane producer that's the

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1 testing entity, they would provide the same
2 information to the utility under the same
3 schedule.

4 And so these are next steps. As I
5 mentioned, the report is already out, it's on
6 our website. We plan to provide technical
7 support to the California PUC during their
8 regulatory process, and specifically we'll be
9 working with the CPUC to see if the risk
10 management and reporting procedures that we're
11 recommending can be integrated with standards
12 for pipeline integrity.

13 We'll also look at identifying an
14 appropriate process for adding new biogas
15 streams such as from anaerobic digesters, or
16 making any changes to the list of constituents
17 of concern, if necessary. We'll also be
18 providing a Web-based tool to calculate that
19 total collective risk I talked about for the
20 compounds that are monitored quarterly.
21 Finally, we'll be evaluating any potential areas
22 for further investigation during the AB 1900
23 mandated updates, which are to occur no more
24 than five years out, it certainly can occur
25 before that if needed. So that concludes my

1 presentation. Thank you for the opportunity.

2 MS. SALAZAR: Thank you, Paul. I
3 failed to tell everyone that we're going to be
4 taking some questions and comments following
5 their presentations. So we're going to open it
6 up to the audience here in the room first, and
7 then, for those of you on WebEx, if you want to
8 chat your question to the host, we can read it
9 for you, or you can use the hand raise tool and
10 we'll open up your line. Thank you. Oh, and
11 also for those of you in the room, please step
12 up to the center podium and speak clearly into
13 the microphone so we can pick that up for our
14 WebEx and also for our recording, and if you can
15 also please provide your business card to our
16 Court Reporter. Thank you.

17 MR. MILKEY: We might have one.

18 MR. AHUJA: Paul, could you clarify
19 whether the testing will be required at the
20 source? This is Kamal Ahuja with the Air
21 Resources Board in the Low Carbon Fuel Standard
22 Program. And I would like to ask Paul if the
23 testing that he mentioned would be required at
24 the source and whether it will be a pre-
25 combustion test or a post-combustion test. And

1 my second question is, would there be any
2 standards for biomethane purification before the
3 biomethane is injected into the pipeline? Thank
4 you.

5 MR. MILKEY: Okay, well, first of all,
6 it is prior to use, so it's pre-combustion, and
7 it would be done at some point prior to
8 injection. I assume it would be fairly close to
9 the source, but it would have to be before its
10 injection. And I think your comment had to do
11 with -- was it verification or --

12 MR. AHUJA: Purification of biomethane
13 for this injection into the pipeline.

14 MR. MILKEY: There's no process there
15 that I'm aware of. Thank you.

16 MS. SALAZAR: Thank you, Paul. Next,
17 we're going to hear from Jennifer Kalafut. She
18 is Advisor to Commissioner Peterman.

19 MS. KALAFUT: Thank you, Rachel. I'm
20 Jennifer Kalafut with the California Public
21 Utilities Commission. I'm going to give just a
22 very brief update on the proceeding at the PUC.

23 So in response to AB 1900, at the
24 beginning of this year the Commission opened
25 Rulemaking 1302008. This Rulemaking is assigned

1 to Commissioner Peterman and, in May of this
2 year the Commissioner issued a ruling outlining
3 the scope of the proceeding. Pursuant to AB
4 1900, the scope will specifically include
5 adopting standards and requirements to ensure
6 human health and safety and pipeline integrity
7 for constituents that may be found in
8 biomethane.

9 We will also be looking at adopting,
10 monitoring, testing, reporting and recordkeeping
11 requirements. We will be exploring processes to
12 review and update the biomethane standards and
13 monitoring requirements going forward, possibly
14 on a five-year basis. And we will also be
15 ordering the gas utilities to adopt new rules
16 and tariff requirements to ensure non-
17 discriminatory open access to gas pipeline
18 systems.

19 In addition to this, we will be looking
20 at defining what a common carrier gas pipeline
21 is for the purposes of AB 1900.

22 Finally, we will be looking at any
23 other enforcement tools that may be necessary to
24 ensure compliance with the Commission adopted
25 standards rules and requirements.

1 In the scoping ruling, we did
2 specifically refer to AB 1900, that the
3 Commission shall give due deference to the
4 report that ARB and OEHHA have developed and
5 delivered to us.

6 In addition, there are a few other
7 issues that were raised by parties prior to the
8 Commissioner releasing her scoping ruling and we
9 talk about these in the ruling, as well. And
10 the first is that the scope will include
11 identifying the costs associated with meeting
12 the Commission adopted standards and
13 requirements; however, because we have a
14 December 2013 deadline on adopting new tariffs
15 and rules around the standards and monitoring
16 requirements for biomethane, it is possible that
17 the identification of costs associated with
18 these rules will take place in a second phase of
19 the proceeding. So we are looking at getting
20 the rules in place first, and then followed by a
21 discussion on the costs.

22 Biomethane promotion issues as called
23 out in AB 1900 will remain in the RPS
24 proceeding, which is a separate proceeding from
25 the one that Commissioner Peterman is looking

1 at.

2 And then finally, as already discussed,
3 solutions regarding impediments that limit
4 biomethane procurement are issues within the
5 purview of the Energy Commission, which is why
6 we're here today.

7 So just to say a little bit on what's
8 been done so far and some key dates going
9 forward, the focus to date has been on
10 supporting ARB and OEHHA on the delivery and
11 development of the report. At the end of March,
12 we did hold a pre-hearing conference followed by
13 a workshop to discuss ARB and OEHHA's
14 preliminary findings. We had a second workshop
15 in Sacramento hosted by ARB and OEHHA to also
16 look at the draft of the report and that report
17 was delivered to us on May 15th.

18 So going forward, one of the key
19 outstanding issues is looking at pipeline safety
20 and integrity. So what we have done is
21 scheduled a workshop for next week on June 4th
22 where we will be exploring these pipeline safety
23 issues. The utilities will be present and
24 presenting along with maybe one or two of the
25 other parties in the proceeding. This workshop

1 will be Webcast and there will be a conference
2 call-in number available, as well.

3 Following that workshop, supplemental
4 testimony will be due by parties in early July
5 and what we're looking for in this testimony is
6 to address recommendations in the ARB and OEHHA
7 report. And for the gas utilities, we have
8 ordered them to include in their supplemental
9 testimony pro forma tariffs and recommendations
10 on the maximum allowable concentration for
11 constituents of concerns, recommendations on the
12 monitoring, testing, reporting, and
13 recordkeeping requirements, and rules to ensure
14 non-discriminatory open access to the pipelines.
15 So we will have a chance, all parties will have
16 a chance, to look at these draft tariffs before
17 moving further in the proceeding.

18 So this gives a sense of the highlights
19 of the proceeding schedule through the end of
20 the year while into the first quarter of 2014.
21 This is per email ruling by our Administrative
22 Law Judge in the middle of May. What I've
23 highlighted here are some of the changes to the
24 schedule that were previously laid out, so this
25 includes the third workshop on June 4th, and

1 because we scheduled that workshop, we did have
2 to push back the date for filing additional
3 testimony in the proceeding, which we've already
4 covered.

5 We are on track to get a decision
6 adopted by the Commission by December 2013 and
7 then we're looking at the first quarter of 2014
8 to make any additional decisions on the costs
9 related to the rules that are adopted.

10 So for more information, these are just
11 some resources for you. We welcome any
12 questions and we hope to see you at the workshop
13 next week.

14 Are there any questions right now?

15 MR. MARISCAL: Thank you, Jennifer. I
16 want to thank Jennifer and Paul for coming on
17 over here and giving us an overview of the
18 presentation on what's been done so far in AB
19 1900. I think it provides a great framework for
20 where we need to go and what we need to talk
21 about today.

22 My name is Gary Mariscal. I work for
23 the California Energy Commission's Renewable
24 Energy Office. I have been the lead Bioenergy
25 Analyst for our office for the last couple of

1 years. I'll be proving a brief presentation on
2 what we're kind of looking for today from the
3 analysts and from the questioners or comments
4 from the public today.

5 So an overview of Policy Objectives.
6 Our long term policy objective in the 2012
7 Bioenergy Action Plan is to create a
8 sustainable, sustaining and competitive
9 bioenergy market in
10 California. So part of that is improving the
11 economics and the viability of biopower,
12 biofuels, and biogas.

13 Biomethane is an important component of
14 this going forward because it will play an
15 important role in providing liquid
16 transportation fuels, it can offset natural gas
17 use at large natural gas facilities, and it can
18 also provide fuel for heating stovetops and
19 residential use.

20 Achieving these objective will require
21 many many options, more options than are on the
22 table right now, and we are striving to make
23 sure that every option that fits within
24 California's values for safety and environmental
25 quality, environmental performance, and economic

1 feasibility are available to both developers and
2 to the public, and to the utilities.

3 So the question is, why do we need to
4 use the pipeline? Because you can use a lot of
5 this gas onsite to create transportation fuels
6 or run a generator. Well, the problem is that a
7 lot of these small-scale generators don't have a
8 good track record for meeting the air pollution
9 standards in non-attainment districts,
10 particularly in San Joaquin and South Coast, a
11 lot of them may need to be shut down as these
12 standards are ratcheted up. Onsite demand and
13 local demand for energy, that is, transportation
14 fuels and electricity, generally don't match the
15 amount of energy that is available to be
16 produced from these sites, and large natural gas
17 facilities are generally more efficient and have
18 lower NO_x emissions than these small-scale
19 generators. Also, the natural gas pipeline is a
20 very efficient way of transporting gas
21 throughout the state.

22 So there are various sources of
23 biomethane and biogas to be considered when
24 you're looking at these standards, and we're
25 looking at the challenges of producing

1 biomethane. There are dairies, publicly-owned
2 treatment works, or wastewater treatment plants,
3 landfill gas, food waste and green waste, that
4 is either source separated or derived from the
5 landfills, themselves, comingled organic and
6 non-organic waste, these would also probably be
7 sources from landfills and other facilities, and
8 of course other animal wastes -- chicken waste,
9 things like that.

10 So staff did a preliminary analysis of
11 what some of the challenges are that we have
12 heard from stakeholders so far. This is
13 definitely not meant to be a comprehensive list,
14 this is just to get us started.

15 There is a lack of confidence that
16 biomethane producers can actually meet the
17 standards produced, which is why we're setting
18 standards in the first place. Interconnection
19 costs relative to project costs, interconnection
20 to the utility pipelines is going to be a very
21 expensive project, and if these projects are too
22 small, these projects won't pencil out if they
23 have to go over a large distance to interconnect
24 to a utility pipeline.

25 Biomethane clean-up technologies have

1 not been fully commercialized in California, in
2 particular. Do we need to look at that and get
3 some additional technologies commercialized? Do
4 new additional technologies need to be
5 developed? And the health protective
6 levels for constituents of concern that the ARB
7 and OEHHA developed is based on data that only
8 looked at three different of the potential
9 sources that were on the previous slide. There
10 just isn't good public data available at this
11 time to develop comprehensive limits for
12 constituents of concern from these other sources
13 without more data.

14 So staff has developed some preliminary
15 recommendations to consider under two
16 subheadings, which is Research. We could look
17 at funding Research and Development and
18 Demonstration projects for biomethane
19 technologies that are capable of achieving
20 biomethane pipeline quality standards
21 consistently and economically. Also, research
22 is needed to identify constituents of concern
23 from different feedstock types. Looking at the
24 feedstocks from the previous two slides ago,
25 there are a lot of constituents of concern that

1 may be in those types of feedstocks that were
2 not identified in the GTI studies for landfill
3 gas, wastewater treatment plants, or dairy.

4 Funding

5 research to develop those constituents of
6 concern will provide a more robust regulatory
7 process.

8 And the other recommendations are under
9 the subheading of Reducing Development Costs
10 Through Economies of Scale, building larger
11 facilities, and this usually involves bringing
12 developers and utilities together to discuss
13 best placement for these projects, so where are
14 the utility pipelines that are available to take
15 more gas? Where is the feedstock, the resources
16 available to develop these projects, locating
17 the best locations? And then continuing to
18 promote and fund research efforts to develop
19 feasible options for transporting raw biogas or
20 biomass to centralized facilities, centralized
21 locations that can upgrade the biogas to
22 biomethane at a larger facility, and take
23 advantage of the economies of scale and inject
24 into the pipeline much closer.

25 So here are some questions to consider

1 as you're listening to the speakers talk today:
2 first of all, is Energy Commission staff
3 characterizing the challenges correctly? What
4 are we missing? Are there other challenges that
5 are going to block the delay of development of
6 these projects in California? Is there anything
7 missing from ARB and OEHHA's recommendations or
8 some unintended consequences in these that we
9 should be addressing? Are there challenges that
10 will limit the utilities from procuring
11 biomethane? There are two different
12 perspectives, we have developers and utilities
13 here, and the utilities need to find biomethane
14 that they can afford that is a good purchase for
15 their Ratepayers. And then, what other actions
16 should the Energy Commission recommend be
17 undertaken to address these, and then prioritize
18 by what needs to be done by 2014 and what needs
19 to be done farther down the road, maybe by 2017?

20 So again, just to remind you, written
21 comments are due by 5:00 p.m. on June 14th on
22 this workshop. Please submit written comments
23 docket@energy.ca.gov. Please also cc me.
24 Please also include the Docket Number and the
25 term Biomethane Procurement Challenges in the

1 subject line of your comments. And again, for
2 those of you on the Web, all of the documents
3 for today's workshop can be located on our
4 website at the link on the presentation right
5 now.

6 And now I'll take any questions or
7 comments that people have in the room right now.
8 Tim.

9 MR. OLSEN: Good morning, Garry, good
10 morning everybody. Tim Tutt from SMUD. And I
11 just wanted to raise two issues. First is Air
12 Resources Board has really been fantastic in
13 working with biomethane producers and
14 considering the zero GHG signature of
15 biomethane, generally. But there are a couple
16 of small issues related to some biomethane
17 contracts, the date when they were signed, and
18 so on, that we're working with ARB to get
19 cleaned up in the 2013 update to the Cap-and-
20 Trade Regulations. So I just wanted to raise
21 that as a potential -- it's not a big concern,
22 but the idea that the Air Resources Board and
23 the Cap-and-Trade and the CEC need to work
24 together on getting conformance on biomethane
25 policy; the Air Board has been really great on

1 working with us on that.

2 And then second, as we all know in the
3 past year or so there have been questions raised
4 about biomethane in various circles, largely
5 related in some cases to what kind of benefits
6 it actually provides to California. And so I
7 would recommend that the Energy Commission
8 engage in some degree of research on this issue.
9 I don't think that the questions about the
10 benefits of biomethane have been based on solid
11 evidence or research, and it would be something
12 that you guys could tackle and try to get to the
13 bottom line as to what the real picture is
14 there. Thank you.

15 MR. MARISCAL: Thank you, Tim.

16 MR. OLSEN: Thanks, Garry. My name is
17 Tim Olsen and I'm Manager of the Energy
18 Commission's Transportation and Energy Office.
19 Some of my comments are going to be around how
20 transportation fits in with electric generation,
21 using the same biogas resource. And part of
22 this is you may not have an answer and we'll
23 bring these topics up in other workshops on the
24 Integrated Energy Policy Report later in July
25 and August. But I just wanted to touch on a

1 couple things since we have the ARB and PUC
2 represented here.

3 I think the question earlier was raised
4 about the natural gas, the quality -- the
5 pipeline quality issue. And in my mind, maybe
6 I've lost track of this, but in my mind there
7 had been a little bit of tension over
8 reconciling in the past the PUC natural gas
9 pipeline gas quality standard which involved the
10 WOBBE Index and I'm not real familiar with all
11 the details of that, so don't ask me a question,
12 but that. And then for natural gas pipeline,
13 natural gas quality in a pipeline. And then
14 also an ARB standard for mobile uses of natural
15 gas in vehicles, slightly different systems from
16 what I understand, and maybe the panel members
17 today will have comments on that. I think if
18 that's still an issue, we probably need to raise
19 that, and whether that needs to be addressed in
20 the future, and as we see more applications of
21 biogas going forward. And then I guess a
22 question about -- I was looking for some comment
23 on tracking of the market transactions that
24 occur, biogas cleaned up, going into a natural
25 gas pipeline, and then coming out, but there

1 could be some marketing and trading on that
2 process, so the question is, is the PUC
3 recording and monitoring -- are you tracking
4 that? Is that part of your OIR? Or is that
5 still a task that has to be done? And it's a
6 factor for out-of-state sources too, just
7 knowing where those -- what the origin is and
8 where it's coming from. It's going to be
9 critical as we take advantage of the lower
10 carbon intensities and the credit systems that
11 are out there, whether it's an electricity REC
12 system, or whether it's an eligibility for a RIN
13 credit for the Renewable Fuel Standard, or
14 whether it's a credit for LCFS. Tracking and
15 monitoring is a really critical part. And you
16 can tell I'm coming from more of a
17 transportation standpoint, but I'd like to hear
18 more about that. If you're not planning to do
19 that, we need to know whether we address that in
20 our transportation side of this.

21 And then also the pricing challenges,
22 how biomethane will compete with conventional
23 natural gas. I'd like to hear more comment
24 about that because I think that's a challenge,
25 too.

1 MR. MARISCAL: Thank you, Tim. There
2 is somebody from the ARB if they wanted to
3 respond to any of the tracking questions on the
4 Low Carbon Fuel Standard as far as natural gas?
5 No? Okay. As far as tracking on the RPS, that
6 is done through the RPS certification process,
7 I'm not completely familiar with the new changes
8 under AB 2196, and how that's going to go
9 forward, so I won't be able to answer that
10 question right now.

11 Does anybody from the panel want to
12 respond to any of Tim's questions or comments?
13 Yes, go ahead, Evan.

14 MR. WILLIAMS: This is Evan Williams.
15 The answer to some of your questions are I think
16 that in the RPS proceedings there is
17 verification and tracking that is done as part
18 of the RPS and I think, Garry, you alluded to
19 that. In terms of the Low Carbon Intensity, I
20 think both Argonne National Labs and DOE and
21 perhaps CARB has also determined that biomethane
22 or Renewable Natural Gas is the lowest carbon
23 intensity fuel of any renewable. So from the
24 standpoint of meeting the objectives of the
25 state to get a low standard, I think it's very

1 low; it is more costly than natural gas, but I
2 think if you take a blended approach of a little
3 bit of Renewable Natural Gas and natural gas,
4 you end up with a slightly higher cost, but a
5 much lower carbon intensity fuel. So I think
6 there are some approaches from a policy
7 perspective that work. I do believe that
8 tracking is going to be something that is going
9 to be required for almost any application of the
10 Renewable Natural Gas that we're talking about,
11 whether it's for the RPS Standards or for the
12 Low Carbon Fuel Standards.

13 MR. THEROUX: Good morning. Michael
14 Theroux, JDMT. Some light here. We see some
15 nice progress across in the coordination between
16 the agencies, it's really encouraging.
17 Fortunately, we're not alone in seeking these
18 kinds of infrastructures, and my question goes
19 to the international research, perhaps, and the
20 infrastructure mechanisms that we see emerging
21 in the United Kingdom, in the Nordic countries,
22 and in Europe, especially in Germany as it moves
23 into the UK. Their challenges are the same
24 challenges that we're facing. The solutions
25 that they're struggling with are a step ahead of

1 perhaps what we're doing, for example, in the
2 United Kingdom. They're struggling with the
3 concept of Hub and spoke networks right now, and
4 making some progress with that. In Sweden,
5 there is a program called Gobie Gas, which is a
6 biomethane production from syngas, from
7 synthesis from gasification of wastes. And in
8 Europe, the whole structure, especially as
9 Germany pushes into the Ukraine, there are
10 questions of the amount of sourcing that's
11 available overall as we build out the
12 infrastructure, which is also pertinent to
13 California. We think we have more than we can
14 possibly use, well, not if we do it right.

15 So I would ask that, is there in the
16 planning a concerted effort to look into the
17 patterns that are developing in other parts of
18 the world? And can we add that into the mix of
19 the research? Thank you.

20 MR. MARISCAL: Yes. Just for a quick
21 response, we will be taking a look at all
22 available reports and recommendations, whether
23 international or not.

24 MR. MAYUGA: Garry, Mark Mayuga, Urban
25 Ideation, LLC, Calmetha, Siemens, ProCone,

1 Lurgi. In answer to your question, I represent
2 Siemens, ProCone, and Lurgi from Switzerland.
3 We are a gasification process and I challenge
4 the ARB to consider gasification of biomass and
5 biomethane to product, rather than to putting it
6 into the pipeline. California has an abundance
7 of natural gas and why take the biogas and put
8 it into the pipeline when you can convert it,
9 liquefy it, and make it into a product like
10 ethanol, like methanol, or DME -- I don't know
11 if you're familiar with DME; DME is a gas form
12 of diesel, virtually no carbon, no sulfur value,
13 so it's a very efficient fuel. So, yes, in
14 answer to your question, Europe is doing quite a
15 bit, way ahead of the United States, and I think
16 that anaerobic digestion quite honestly is
17 archaic compared to what other systems are out
18 there, which have virtually no emissions and are
19 very efficient. So, yeah, Europe is way ahead
20 of us. Thank you.

21 MR. MARISCAL: Thank you.

22 MR. MORROW: I had a chance to spend
23 six weeks in Germany and Switzerland --

24 MR. MARISCAL: Will you please
25 introduce yourself? Sorry.

1 MR. MORROW: Oh, I'm Paul Morrow with
2 Morrow Renewables. I had a chance to visit a
3 digester project in Basel, Switzerland last year
4 and it's true that they are ahead of us in many
5 regards, but they also don't have the sources of
6 energy that we have here. And the reason to
7 typically liquefy fuel is because you don't have
8 a transportation network, that's why it's in
9 Australia, they don't really have the network to
10 get natural gas from the interior of the country
11 out to the port, so liquefaction isn't really an
12 option. I think compressed natural gas is still
13 one of the best options we have because we have
14 so much money invested in the infrastructure to
15 deliver it.

16 MR. MARISCAL: Thank you. Any other
17 questions? Are there any questions from the
18 Web? Okay. I think we had one more question
19 for Jennifer at the CPUC.

20 MS. KALAFUT: Thanks, Garry. This is
21 Jennifer at the CPUC. There was a question that
22 came in through the WebEx, "Will the costs under
23 consideration in the first quarter of 2014
24 include interconnection costs? Or will they
25 only be for compliance with the requirements?"

1 If not, when will interconnection costs be
2 considered? This is the single largest obstacle
3 towards biomethane injection, so we hope that
4 they will be considered." I'm just reading the
5 question.

6 I think that Garry answered a bit of
7 this in his presentation. For the present time,
8 the costs associated with meeting the Commission
9 adopted standards and requirements will be
10 addressed in our proceeding. I'm assuming that
11 the participant on the WebEx is talking about
12 tie-in to a gas pipeline and not electrical
13 interconnection. Electrical interconnection
14 would be dealt with in a different proceeding at
15 the PUC.

16 I think Garry mentioned in his
17 presentation that the CEC is going to be looking
18 at impediments for biomethane interconnection to
19 gas pipeline. In terms of costs associated with
20 those and how we may address them, currently
21 it's not specifically within the scope of our
22 proceeding, but I would not rule it out as
23 something that we could possibly look at going
24 forward if there is a high concern around this.

25 MR. MARISCAL: Thank you, Jennifer.

1 Are there any other questions from the Web or
2 from the room? Are there any questions on the
3 phone? Okay, I'm going to go ahead and turn it
4 over to our panel.

5 Today we are very lucky to have five
6 panelists who know a heck of a lot more than I
7 do about this information. I'm going to turn it
8 over to Jim Lucas first, with Southern
9 California Gas Company.

10 MR. LUCAS: Thanks, Garry, I appreciate
11 it. Good morning, everyone. It's great to be
12 here today and to be part of this panel to
13 discuss some of the challenges of putting
14 biomethane to the pipeline.

15 All right, here you'll see the overview
16 of today's topics. Some of the questions that
17 were just asked during the session just now,
18 I'll answer some of those questions. I know
19 Garry brought up the interconnection costs
20 relative to project costs, and that's one of the
21 slides I have is for a lifecycle project of
22 putting biomethane to the pipeline, you know,
23 what percent of those costs are related to
24 interconnection.

25 All right, the next few slides will

1 cover a high level overview of the process an
2 interconnector would go through when seeking to
3 put biomethane into the pipeline. The first
4 stage of that is doing an interconnection
5 capacity study. In this case, the
6 interconnector would contact SoCalGas, and they
7 would give us a proposed location of where they
8 want to inject the biomethane. They would also
9 give us the amount of biomethane they want to
10 inject. At that point, we would take that
11 information and we would determine the nearest
12 pipeline that has the takeaway capacity to
13 accept that volume. It could be right in front
14 of that facility, it could be 50-feet away, it
15 could be six miles away, it all depends on that
16 particular pipe and how far we have to go out to
17 find that pipeline that has the capacity.

18 Some things to keep in mind: like I
19 said, the adjacent line or the line in the
20 street in front of that facility may not have
21 the capacity, so you have a wastewater plant
22 that's mostly in a residential or commercial
23 area, think about it being August, you know, of
24 the summer at 2:00 a.m., and how many customers
25 in that area are going to be using gas. So

1 water heaters are pretty much shut off,
2 restaurants are not in operation, you don't have
3 heaters going on, it's pretty much the capacity
4 in that system if it's mostly residential and
5 commercial, there's not going to be a whole lot
6 of capacity to inject biomethane. So that's why
7 it may take a mile or two miles to find that
8 nearest line.

9 Also, it's very costly to install
10 pipelines in today's city streets. You know,
11 material, if you look at the cost of metal over
12 the last 10 years, it's quadrupled. If you look
13 at the labor costs in California for a pipe
14 fitter, compared to states like Texas or North
15 Carolina, our labor rates are 30 to 50 percent
16 higher than those states.

17 Also, with the permitting and
18 environmental regulations, I mean, as you know
19 it's tough to get things permitted now days. If
20 you're looking to do a pipeline extension in a
21 major city street, that city may force you to do
22 that work at night. If you're going to do it at
23 night, you're talking probably double-time, you
24 know, for labor. So, again, it's very expensive
25 to do pipeline work in busy city streets.

1 So looking at the diagram here, when
2 the capacity study is completed, we give a
3 report back to the interconnector and basically
4 it might say, you know, the nearest pipeline is
5 two feet away that can handle capacity, or 2,000
6 feet away, it would be four-inch pipe that would
7 need to be installed, and the approximately cost
8 is \$1 million, whatever that cost would be. At
9 that point, the interconnector will look at that
10 cost and say -- and this is a high level cost --
11 they would say, "Does that price still fit
12 within my economics of doing a pipeline
13 injection project?" If the answer is yes, they
14 would go to step 2. Step 2 is doing a
15 Preliminary Engineering Study and all these
16 studies are paid for by the interconnector,
17 these are all based on actual costs. This is a
18 more detailed study for that pipeline extension
19 that was identified in the Interconnection
20 Capacity Study. So we would go out there, look
21 at the streets, look to see what the route would
22 be, we'd develop some cost estimates for land
23 acquisitions, site development, provide a way
24 for metering, things like that so, again, we
25 have a more refined estimate for that pipeline

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1 extension.

2 We'd also develop a Point of Receipt
3 estimated cost, and the Point of Receipt is the
4 facility where the gas goes from the
5 interconnector into the SoCalGas pipeline, so
6 that would have monitors, regulators, valves,
7 owner facility, things like that. So now you're
8 going to have two costs, a Refined Cost to run
9 that pipeline to the nearest pipeline that can
10 accept the capacity, and also you have a Point
11 of Receipt cost. So say now your cost to do
12 both of these is, say, \$2.5 million, the
13 interconnector would then say, "Okay, those
14 economics still work for my project, I'll move
15 on to the next phase." The next step is to do a
16 detailed Engineering Study, again paid for by
17 the interconnector, and pretty much at the end
18 of this process, the interconnector would be
19 given a package that's ready to be installed by
20 a pipeline contractor. It will have, you know,
21 all the costs of construction, material list,
22 construction drawings, and all the prices would
23 be prepared. Again, so you have a Refined Cost
24 estimate and at that point the interconnector
25 would say, "Okay, I want to continue, you know,

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1 the economics still work for my project and
2 let's go ahead to the operation and funding."

3 Now, there's three different ways a
4 project could be funded for interconnection.
5 The first, the interconnector may elect to, A)
6 pay 100 percent of the cost to the utility,
7 including applicable CIAC taxes, and I'll cover
8 that later in today's presentation, to complete
9 installation of the necessary facility. So,
10 again, we would do all the work, the
11 installation of the pipeline and the
12 interconnection, and pretty much the
13 interconnector would give us a check for that
14 amount. Step 2, or option B, the interconnector
15 would pay 100 percent of the cost to the utility
16 to complete the installation of the necessary
17 facility, receive a refund of those advance
18 funds after gas first flows through the Point of
19 Receipt, and be charged an incremental
20 reservation rate on a going forward basis. So
21 basically say it's a \$2 million project, a check
22 is given to SoCalGas upfront, the facility is
23 built, the gas starts flowing, that payment is
24 given back to the interconnector, and then the
25 interconnector will pay off those costs over a

1 three to 20-year period, depending on what the
2 interconnector wants to go with, so this is a
3 different option. The third option is the
4 interconnector could install the facilities
5 themselves under the direction of the utility,
6 and transfer ownership of the facilities, along
7 with payment for utility supervision and any
8 applicable CICA taxes. So those are the three
9 different ways a project could be funded.

10 So let's assume that, again, this works
11 for the interconnector, go to the next phase,
12 the job would go to construction, again,
13 depending on the way that the interconnector
14 wants to fund it, it could be done by the
15 utility or the interconnector. And at the end,
16 there will be a reconciliation of costs. So,
17 again, all these costs are paid for by the
18 interconnector, so even though the initial
19 payment might be \$2 million, if all the actual
20 costs came in at \$2.1 million that we would
21 build the interconnector for the extra \$100,000.

22 A few keys to ensure a smooth process,
23 generally this process takes 18 to 24 months, so
24 hopefully that fits within the interconnector's
25 timeline. If you call us six months in advance,

1 that's really not doable. Again, so it takes
2 almost two years to get this process done. The
3 next is that, you know, for the design of the
4 facilities, it can be done by the
5 interconnector, it's been our experience that
6 when the design is done by the interconnector,
7 there's a lot of back and forth between SoCalGas
8 and their engineering firm. SoCalGas has our
9 specifications for, you know, pipelines and
10 interconnection, and not only will that increase
11 cost because there's a lot of back and forth, it
12 may actually delay your project, as well. So
13 that's just based on our experience.

14 Something that SoCalGas has available
15 on our website is a Gas Transmission and High
16 Pressure Distribution Pipeline Interactive Map.
17 On this map, you can go on there and type in an
18 address in a certain city, and it will show you
19 the nearest pipelines to that location, high
20 pressure pipelines. Again, this doesn't mean
21 that pipeline has the capacity to accept the
22 amount of biomethane that the interconnector
23 wants to install, but this gives you a general
24 idea that, you know, I have a high pressure
25 pipeline one mile away, or in the front door, as

1 well.

2 There's also a National Pipeline
3 Mapping System available, too, and you'll see
4 both of these Web links on this slide in case
5 you want to access those or see where those
6 pipelines are.

7 As I mentioned earlier, there's
8 something called Contributions in Aid of
9 Construction or CAICs. So when there is a
10 contribution made to the utility, whether it's
11 cash or a asset, it's a possibility that the
12 utility may be required to pay Federal and State
13 tax based on the value of that cash or that
14 asset. If that is the case, then the utility
15 will need to pay certain tax rates based on the
16 income tax component of contributions and
17 advances.

18 There's something called the Safe
19 Harbor Questionnaire, and this questionnaire is
20 filled out by the interconnector and, based on
21 the answers to that questionnaire, that will
22 determine whether or not the facility, being an
23 interconnection facility, will be qualified as a
24 CAIC. If it is, then say the project costs \$2
25 million, based on the way the tax is right now

1 in 2012, the CAIC would be a value or an
2 incremental amount of \$440,000 for
3 interconnection. Come 2014, if the American
4 Taxpayer Relief Act of 2012 is not extended at
5 the end of 2014, the new tax rate will be 35
6 percent. So, again, say you have a project of
7 \$2 million, and the facility is not exempt from
8 the CAIC, then you'll have incremental costs of
9 \$400,000 to \$700,000, depending on which year it
10 is.

11 These next two slides, what we've done
12 is we've broken down the costs to inject
13 biomethane into the pipeline, and we've broken
14 that down by five different components: one is
15 the Capital Costs, that would be biogas
16 upgrading plant, the second is the O&M for the
17 biogas upgrading plant, third is the Utility
18 Point of Receipt Upfront Costs, and the Point of
19 Receipt is, again, like the facility that
20 measures all the gas going into the system, it
21 has monitors, the owner of facility, things like
22 that, we also have the Point of Receipt O&M, and
23 you have the Pipeline Extension Costs that goes
24 from the injection point to the nearest pipeline
25 that has the capacity.

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1 I want to point out two things on this
2 slide. If you look at the conditions of this
3 slide, it's based on 1.5 million standard cubic
4 feet per day of biogas over a 15-year scenario,
5 so, again, this is a lifecycle cost type of
6 graph. On the X axis, we've gone and included
7 different pipeline extension links covering from
8 1,000 feet to two miles. So if you look at the
9 left-hand side, you know, the 1,000-feet of
10 pipeline extension, the combined Point of
11 Receipt Upfront Costs and the O&M, the combined
12 percent of total costs is 11.5 percent -- let's
13 make it 12 percent just for simplicity reasons.
14 So let's assume that we can reduce the Point of
15 Receipt cost either through the O&M or the
16 upfront costs by a third, which is four percent,
17 in this case, assuming you can upgrade and
18 inject biomethane at a cost of \$8.00 per MMBtu,
19 you know, four percent of \$8.00 is \$.32, so by
20 decreasing your costs on the Point of Receipt
21 side, it's not likely going to make or break a
22 project to inject biogas into the pipeline.

23 The second point is, look at the graph
24 where it has the two miles of pipe on the right-
25 hand side, you'll see that the pipeline

1 extension costs equate to about 15.3 percent of
2 the lifecycle cost. Again, at \$8.00 per MMBtu,
3 15 percent, you know, about \$1.20. So one-sixth
4 of your costs in this case are going to be from
5 that pipeline extension, that's why location is
6 key when you're trying to find a facility or a
7 location to inject biomethane.

8 The next slide is the same identical
9 slide, just different conditions, so instead of
10 heaving 1.5 million standard cubic feet per day
11 of biogas for 15 years, we assumed 360,000 cubic
12 feet per day, which is about a fourth of the
13 previous volume. So, again, let's look at the
14 two different areas. On the one side you have
15 the 1,000-foot, and you have the combined
16 percent of lifecycle cost for the Point of
17 Receipt is 21 percent, which previously it was
18 about 12 percent. So, again, assume you can
19 reduce those costs by one-third, that's about
20 seven percent. What I want to point out is
21 that, at this volume, it's going to cost you
22 probably at least \$15.00 for MMBtu to inject
23 this biomethane into the pipeline, so seven
24 percent of \$15.00, you're looking at a dollar.
25 So, again, looking at it from a \$15.00

1 standpoint, between \$14.00 and \$15.00, is that
2 going to make or break a biomethane injection
3 project? Likely not at that cost.

4 Also, look at the two mile graph. Now,
5 if you need to install two miles of pipeline to
6 get to the nearest line that can accept the
7 capacity, that's going to be a quarter of your
8 lifecycle cost to produce biomethane. So,
9 again, location is key.

10 Some challenges to produce biomethane.
11 You know, from a policy standpoint over the last
12 18 months, you know, we've had the suspension of
13 biomethane for RPS, I think that kind of stalled
14 the market a little bit. Also, there's never
15 been incentives for biomethane injection.

16 Currently we have AB 1900 and with an
17 unknown pipeline quality spec until the end of
18 this year, if you are looking to design a biogas
19 operating plant, you don't know what that final
20 spec is going to be. So we don't know what
21 limits of H₂S, limits of Siloxanes, so it may be
22 tough to design a biogas upgrading plant based
23 on an unknown design requirement. And again,
24 currently there's still no incentives, as well.

25 In the future, we hear something about

1 the Low Carbon Fuel Standard, you know, using
2 biomethane for transportation fuel, that has a
3 lot of possibility. If you look at the value of
4 biomethane when used for transportation has
5 three components, it'll have the value of the
6 commodity, say the border price of natural gas
7 is four bucks, you have the Low Carbon Fuel
8 Standard which is still in the course, but
9 hopefully once it gets out, that can generate
10 credits for you, and the credits right now are
11 trading around \$40.00 per ton, which equates to
12 \$3.50 per MMBtu. There's also something called
13 Renewable Identification Numbers, or RINs on the
14 Federal side. Again, those are trading as well
15 for biomethane and those, based on where they
16 are today, the total value of the biomethane for
17 transportation over the last 18 months has
18 ranged between \$12.00 and \$20.00 based on the
19 value of all three of those elements -- the
20 value of the commodity, the Low Carbon Fuel
21 Standard credit, and the RINs. So there's a lot
22 of potential there.

23 I guess we heard earlier, you know,
24 project scale is always difficult. The general
25 rule of thumb that we've always used is that to

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1 economically produce biomethane, you need about
2 1.5 million standard cubic feet per day of
3 biogas. That's assuming you can sell the biogas
4 at \$9.00 to \$12.00 per MMBtu.

5 You also need to have a consistent and
6 predictable biogas supply. You know, so if you
7 have a digester and it's not producing what you
8 thought it would, obviously your revenues from
9 the sale of biomethane is going to be much less.
10 Also, you don't want fluctuating types of gas
11 composition, you don't want oxygen to be, you
12 know, one day .1 percent, and the next day be
13 1.0 percent; your upgrading plant may not be
14 designed to handle those fluctuations.

15 Also, the incentives for biomethane
16 production are uneven. If you look at the
17 diagram there, there's two different ways that
18 power could be produced using biogas or
19 biomethane. So looking at the top route, you
20 have a digester producing biogas, it goes into a
21 biogas upgrading plant producing pipeline
22 quality gas, it's injected, goes into the
23 utility pipeline, and if it's not going into an
24 RPS certified power plant, there's no investment
25 tax credit for that scenario, yet you're

1 producing renewable power.

2 At the other end on the bottom side,
3 you look at the digester producing biogas, the
4 biogas goes into an onsite generation facility,
5 you know, onsite, and you're producing renewable
6 power, as well. But in that case, that facility
7 is eligible for the Investment Tax Credit. So,
8 again, so both ways you're producing renewable
9 power, yet in one way the ITC applies, and in
10 one way it does not.

11 Lastly, I'll cover our Proposed Biogas
12 Conditioning/Upgrading Services (BCS) Tariff.
13 On April 25th of 2012, SoCalGas filed an
14 optional tariff where we are seeking to own,
15 operate, and maintain biogas upgrading plants on
16 customer facilities. The parties involved in
17 this proceeding filed a Settlement Agreement on
18 May 3rd with the Commission and we're currently
19 awaiting a decision. SoCalGas will not own the
20 commodity that goes into the upgrading plant, so
21 the way we describe this, it's kind of like a
22 car wash, you go to the car wash, you give them
23 your car, throughout the process, you always own
24 the car, and at the end you get a clean car. In
25 this case, you know, you provide us with your

1 biogas, we clean it to whatever quality that you
2 want, and at the end of the upgrading plant you
3 take possession of it, and the customer chooses
4 what they want to do with it, use it onsite for
5 CNG, inject it into the pipeline, whatever the
6 case is.

7 For this proposal, shareholders will
8 bear 100 percent of the risk, Ratepayers will
9 have no involvement in this service. And the
10 optional BCS Tariff will be promoted on a
11 competitively neutral basis with periodic
12 reporting to the Commission. So when the
13 customer calls, if they're interested in doing
14 biomethane injection, we'll describe our tariff,
15 but also give them a list of vendors that can
16 provide similar services. And also, just to be
17 clear, for this tariff, it's completely separate
18 than the interconnection process. So, you know,
19 if you want to pursue the biogas conditioning
20 tariff, as well as injecting that to the
21 pipeline, you have two separate processes, two
22 separate contracts, they're totally separated.

23 So looking at the diagram, again real
24 fast, you have customer-owned biogas, it would
25 go into the upgrading plant that SoCalGas would

1 upgrade to pipeline quality, and at that point
2 the customer takes possession of the biogas and
3 they decide what to do with it. One thing to
4 make clear, SoCalGas does not buy biomethane, we
5 are not authorized to buy it from customers; we
6 frequently get calls from customers asking that
7 question, and that's something that we're not
8 authorized to do currently.

9 And that's it. Thank you very much.

10 MR. MARISCAL: All right, thank you,
11 Jim. I'm going to ask that we hold all questions
12 until the end of the panel presentations, and
13 then we'll go through all the questions one-by-
14 one. Next we have PG&E. We have Bill Raymundo.

15 MR. RAYMUNDO: First of all, I'd like
16 to thank you guys for allowing me to come here
17 and thank you for being here. I actually have
18 four slides to show you.

19 First slide, I'd just like to emphasize
20 that PG&E supports policies for biomethane as
21 another viable alternative fuel, and that PG&E
22 is committed to the development of biomethane as
23 an alternative fuel.

24 Regardless of what fuel we transport,
25 we're obligated to make sure that we transport

1 safe, reliable gas or fuel that is known to be
2 consistent in its quality.

3 MR. MARISCAL: Bill, can you move the
4 microphone a little bit closer? Thank you.

5 MR. RAYMUNDO: This is very important
6 because of our concern to the health of our
7 employees and customers and the integrity of our
8 power plant system, and the safe operation of
9 our customers' appliances and equipment.

10 There is one major issue that we are
11 very concerned with, and that's our
12 interconnection with our low demand pipelines,
13 which we believe require extra safeguards until
14 we've gained enough experience in those areas.

15 We have successfully accepted
16 biomethane in the past in the pipeline and look
17 forward to gaining experience with additional
18 feedstock. We are reviewing the biomethane
19 experience of other utilities, both the U.S. and
20 worldwide, to incorporate lessons learned. As a
21 matter of fact, we have purchased a reference
22 library from Elsevier to allow us access to a
23 lot of the periodicals worldwide.

24 PG&E is also continuing to develop and
25 refine its Biomethane Acceptance Plan and will

1 present its updated proposals to CPUC in July of
2 2013.

3 PG&E looks forward to working with the
4 industry and Regulators to enable the safe and
5 reliable delivery of biomethane in California.
6 And if you need more information, please feel
7 free to call me. My phone number and email is
8 shown in the slide. Thank you.

9 MR. MARISCAL: Thank you. Our next
10 presentation is going to be a joint presentation
11 from the Coalition for Renewable Natural Gas, we
12 have Evan Williams from Cambrian Energy and Paul
13 Morrow from Morrow Renewables.

14 MR. WILLIAMS: Good morning. I'm
15 pleased to be here representing the Coalition
16 for Renewable Natural Gas, which is a 501(C)(3)
17 trade association with a fairly broad spectrum
18 of membership that includes developers like the
19 companies you see before you, and my company,
20 and Paul Morrow's company, the solid waste
21 industry, utilities, engineers, the finance
22 community, gas marketers, and members of
23 organized labor. So as you can see, most of the
24 participants that are necessary to implement a
25 project for Renewable Natural Gas are

1 represented in our membership.

2 The task we were given, and we did this
3 collaboratively with the working group of our
4 coalition, were California's challenges and
5 potential solutions to procuring biomethane,
6 which I will call Renewable Natural Gas, or RNG.
7 And what we're going to give you is an industry
8 perspective.

9 I'd like to have you meet the
10 presenters. To my left is Paul Morrow, who is
11 the Managing Director of Morrow Renewables, and
12 Morrow Renewables has developed six renewable
13 natural gas projects. Paul and his family are
14 the former owners of South Tex Treaters, which
15 was one of the largest gas treating firms in the
16 United States, which was recently sold to Kinder
17 Morgan, and Morrow Renewables also was a co-
18 founder of the Coalition of Renewable Natural
19 Gas.

20 I'm Evan Williams. I'm President of
21 Cambrian Energy Development. And over the last
22 30 years, we've actually developed 50 landfill
23 gas to energy projects of which three of those
24 have been Renewable Natural Gas projects, and we
25 are a co-developer of the largest RNG project in

1 the United States at the McCommas Bluff Landfill
2 in Dallas, Texas. I'm currently Chairman of
3 the Coalition and Cambrian Energy is also a co-
4 founder of the Coalition.

5 I'd like to tell you that Paul and I
6 are survivors of the very rigorous selection
7 process to appear here today, and Paul was
8 selected for two reasons, one is he's wicked
9 smart, and two is, he could afford the plane
10 ticket from Texas to Sacramento.

11 Actually, I was selected for three
12 reasons, first is I'm old, the second is I could
13 scrape together the bus fare from Los Angeles to
14 Sacramento, and the third actually are my
15 political qualifications, and since this is a
16 political process that we have gone through with
17 the adoption of AB 1900, and it's a political
18 process on the regulatory schemes, I thought it
19 only fair that we establish my political
20 credentials, and I want to share those with you
21 today.

22 Now, that's actually a picture of Rhys
23 Williams, who was an actor in the 1940's and
24 1950's, probably his most important role was as
25 my father. He appeared in two films that won

1 Best Picture in 1941 and 1942 when he appeared
2 with people like James Cagney and Gregory Peck.
3 Now, you might ask, what does this have to do
4 with my political qualifications? And indeed, I
5 remind you, this is California, and in
6 California if you're an actor, you can be
7 Governor, you can be a State Senator, and if
8 you're the son of an actor, as I am, you qualify
9 to serve as Lieutenant Governor or member of the
10 California Energy Commission. So having sort of
11 conclusively established my credentials in this
12 regard, I wanted to share with you a little bit
13 of what we're going to talk about today.

14 The goal, first of all, of AB 1900, and
15 I think it's important to keep this in mind as
16 we go through this, the potential sources of RNG
17 in California; the RNG market size -- and this
18 is something I also want you to pay attention to
19 because there has been a lot of attention paid
20 to this, but in terms of the relevant size, I
21 think it's important to keep this aspect in mind
22 as we go through this; the technologies used and
23 the minimum project size required; Developer's
24 Essential Requirement -- and, under the
25 strictest of confidence, I'm going to reveal to

1 you the secret formula that's involved in that;
2 the California impediments of development of RNG
3 projects; and a menu of potential policy
4 solutions. And I stress this is a menu, but I
5 also want to let you know that what we're going
6 to offer up today is potential solutions -- are
7 solutions that have worked elsewhere in the
8 country. I have never been accused too often of
9 creative thinking, so I borrowed freely from
10 what others have done successfully in other
11 states and even at the Federal level, and even
12 with respect to other renewables here in
13 California.

14 I'm going to talk a little bit -- and
15 this goes to some of the comments that were made
16 earlier about the need of synchronization of the
17 State's clean air and renewable energy policies,
18 which are sometimes in conflict, and then of
19 course, lastly, we're going to talk about a
20 critical mass problem and lesson that needs to
21 be learned.

22 Stated Goal of AB 1900. There is a new
23 Public Utilities Code Section adopted as part of
24 that statute that says it's going to promote the
25 in-state production and distribution of

1 biomethane, and it's going to facilitate the
2 development of a variety of the sources of in-
3 state biomethane. And what are those sources?
4 They've been touched on earlier, basically they
5 are anaerobic digestion of organic matter from
6 landfills, digesters at wastewater treatment
7 plants, or POTWs, and digestion or co-digestion
8 of other organic matter, fats, oil and grease,
9 agricultural waste, and even municipal solid
10 waste.

11 All right, potential contribution by
12 RNG to California gas market, all uses. We have
13 a very large natural gas market in this state.
14 If we did all of the resources that we have in
15 California, we're probably looking at one
16 percent or maybe less of all the gas used in the
17 state. Now, having said that, RNG is a baseload
18 storable dispatchable renewable fuel and would
19 contribute very significantly to the volume
20 toward achieving California's renewable electric
21 power standards, as well as -- your point
22 earlier -- the low carbon transportation fuel
23 goals of the state.

24 The size of the organic matter
25 resources, their proximity to pipelines, which

1 have been mentioned earlier, and the substantial
2 capital investment required for these are
3 limiting factors. Basically projects are going
4 to typically be developed at larger landfills
5 and at digesters relatively near pipelines. And
6 I think, Jim, it goes to your point earlier.

7 All right, and Garry, maybe this
8 answers one of the questions you asked in your
9 presentation earlier. RNG Production
10 Technologies. Is this new? Or is it relatively
11 old? Basically all the technology used today to
12 upgrade these resources to Renewable Natural Gas
13 really comes out of the oil and gas industry.
14 It's proven technology, it's been used for many
15 years. There are projects in the Renewable
16 Natural Gas industry that have operated for more
17 than 30 years, for instance, the largest
18 landfill in the country at one time, the Fresh
19 Kills Landfill on Staten Island in New York,
20 that project has been producing Renewable
21 Natural Gas for more than 30 years. There are
22 projects in Texas and Ohio at some very large
23 landfills there that have been producing
24 Renewable Natural Gas for more than 20 years,
25 though this is not a new phenomenon and this is

1 not new technology.

2 I submit that I don't think there are
3 significant amounts of R&D that's required to
4 have this be viable technology today, and I'll
5 let my colleague who has been in this business
6 for a lot of years address any questions you may
7 have in that regard.

8 Large investment required -- and there
9 are limitations on access to market. So when
10 you look at the 594 projects that the Landfill
11 Methane Outreach Program says have been
12 developed on landfills, only 39 of those
13 projects are RNG projects, that's about 6.5
14 percent. These are not easy to do and you need
15 to find the right location to achieve these. So
16 we need to keep that in mind when we talk about
17 adopting rules to encourage this in the state.

18 Scale of RNG Projects. There's
19 millions in capital required. This is a picture
20 of our project at the McCommas Bluff Landfill.
21 At the top you see what the equipment looks
22 like, and this is before the recent expansion we
23 completed; on the bottom is this other works
24 model showing what the expanded facility looks
25 like. There's about \$50 million of capital

1 involved in that project, this is not a hobby.

2 Landfill gas wells are a fairly
3 intensive process, this is the process that goes
4 in, you see the landfill gas well picture at
5 your lower left. In the Dallas project, there
6 are 400 of these wells at approximately \$10,000
7 per well. The well field capital replacement
8 are fairly expensive, about 10 to 15 percent per
9 year of the original capital amount.
10 Occasionally, you'll see battles engaged in
11 between large pieces of yellow equipment in that
12 plastic pipe, I've never seen the plastic pipe
13 win that battle, which means it needs to get
14 replaced.

15 So this is an ongoing process, the body
16 of land in which these -- at least in landfills
17 -- are located is moving, so there's constant
18 care and attention needed for that, and for
19 these projects you need to make sure that air
20 does not get in the process, which brings with
21 it nitrogen, which affects pipeline quality spec
22 standards and the ability to meet it.

23 The Business Model that an RNG
24 developer has and an essential requirement is
25 basically this: you've got to make money. You

1 need a return of and a return on your
2 investment. And basically there is proven
3 technology that's used in these, but these
4 projects involve very high financial risk, and I
5 illustrate that because in our project in Texas,
6 there were three prior owners, all of whom went
7 into bankruptcy, where the current owners and
8 co-developers of that -- and we used the same
9 technology, but we're successful today because
10 we basically employed better financial
11 engineering, and that's very key, you're going
12 to hear that in a theme as we go through the
13 rest of this presentation.

14 The key to successful development of an
15 RNG project? You have to meet the secret
16 formula. Okay, and this is the point where I
17 probably should ask you to raise your hands and
18 be sworn to secrecy on this because otherwise
19 I'm going to create a whole roomful of
20 competitors. What is the secret formula? You
21 got it, here it is -- revenues have to exceed
22 expenses. The other part of that -- and this is
23 very important -- predictably; simply stated,
24 not easy to achieve. And the predictability
25 part of this over time is one of the things that

1 can impact on financing, and I know Frank
2 addressed some of this earlier when you hear of
3 biofuels and the difficulty of achieving that
4 very simply stated formula.

5 Costs for LFG Landfill Gas to Pipeline
6 Quality Renewable Natural Gas Project. I wanted
7 to put some perspective on this in terms of
8 dollars and cents, and if there's attorneys in
9 the room and these numbers -- I'm going too fast
10 for you, just raise your hand and I can slow
11 this down a little bit. These are basically the
12 charts that indicate basic costs that go into --
13 and this doesn't include overhead, but this does
14 include most of the kinds of costs that talks to
15 produce for a two million feet per day Renewable
16 Natural Gas project. Your attention to the
17 lower left-hand corner, \$5.48 per million Btu,
18 okay? What happens if all you can get is the
19 commodity prices? Jim alluded to this earlier
20 in his presentation. Today, at least at May
21 24th, commodity price Henry Hub natural gas was
22 \$4.23. If that's all you have available, that
23 math does not work. So the problem is the
24 commodity price doesn't meet the secret formula
25 requirement. So therefore what leads to

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1 development in California? You need access to
2 markets, you have to have that, if you can't
3 sell the renewable energy to customers, then how
4 much is available and how cheaply you can
5 produce it makes absolutely no difference.

6 The State policies must increase
7 positive dollars and reduce negative dollars,
8 and I'm going to tell you what that means in a
9 second here. The environmental policies have to
10 be synchronized: clean air versus renewable
11 energy, and we have some inconsistency today in
12 those two objectives in the State of California.

13 Okay, what hinders the access to the
14 markets? Some of this has been addressed
15 earlier. Physical constraints, project not too
16 close to a natural gas pipeline, utility or
17 other customer constraints, high interconnection
18 costs, we've talked about that, pipeline company
19 gas spec tariffs don't accommodate the
20 differences in RNG from natural gas because RNG
21 does not contain the higher chain hydrocarbons
22 that are present in natural gas, therefore its
23 inherent Btu value is lower. RNG price
24 constraints, insufficient price, we just
25 addressed that. Legal and regulatory

1 constraints, you don't want to be regulated as a
2 utility, there are prohibitive air emission
3 regulations in certain cases, and before AB
4 1900, there was an absolute prohibition under
5 Health and Safety Code 25421, which AB 1900
6 basically abrogated.

7 What are the positive dollars and
8 negative dollars? Well, positive dollars
9 basically is any law or policy that tends to
10 increase revenues or decrease expenses.
11 Negative dollars are the reverse of that. The
12 decrease revenues and increase expenses.

13 All right, examples of positive
14 dollars: enhanced revenues, feed-in-tariffs. We
15 have an example like the CREST Tariffs, there
16 are tariffs used in solar and wind that have
17 been very successful, providing higher prices
18 for those type of renewable energy sources. Tax
19 credits -- Federal and State. Section 29
20 credits, which used to be available for RNG, but
21 turned into Section 45 tax credits, which are
22 only available to electric power projects. All
23 right, they can be monetized with third parties
24 if the developer doesn't have the tax appetite
25 for them. These were very helpful in getting a

1 lot of projects done. Supplemental energy
2 payments, grants, and other government supports,
3 transferable renewable energy certificates,
4 transferable emission reduction credits,
5 exemptions from reductions of certain expenses,
6 that's another area of positive dollars. Taxes,
7 if you're exempt from sales tax, energy tax, ad
8 valorem, or property taxes, it's very helpful.
9 Exemptions from regulation and reporting,
10 utility regulation reporting requirements,
11 expedited permitting procedures, negative debts
12 rather than a full EIR; all of these are
13 positive dollar contributions to projects.

14 The reverse are that of the negative
15 dollars: what happens when people add taxes in
16 the sales tax, energy tax, property tax?
17 Regulations that increase capital expenditures
18 for equipment, permitting and installation, and
19 this can be restrictive. Air emissions
20 standards that cause more equipment to try and
21 meet the standards, pipeline standards that
22 increase expenses for delivery of gas, you know,
23 basically the high minimum Btu standards,
24 extensive trace constituent standards, and
25 continuous or frequent monitoring or testing for

1 trace constituents that are difficult to
2 measure; these all add costs to a project,
3 they're negative dollars.

4 Positive dollar regulations and
5 mandatory market access work. And when I say
6 this isn't new, this is actually taken -- and a
7 lot of these thoughts are taken -- from a
8 presentation I did back in 2005 for the Mid-
9 America Regulatory Conference, which was the 17
10 State Public Utility Commissioners, and they
11 asked virtually the same questions that were
12 asked today, which is what can you do to
13 basically enhance renewable energy development?
14 It was a broader question then. And it was just
15 a very interesting chart. This chart actually
16 pertains to wind development and it starts in
17 1980 and goes through 2003. Well, what happened
18 to 1980? The Public Utilities Regulatory Policy
19 Act which basically opened up the electric power
20 markets; and then you can see the path of
21 development that happens here for wind projects
22 when you have standard offers which basically,
23 you know, even somebody like me, you had to
24 check three boxes and spell your name correctly,
25 you got a financeable energy sale agreement,

1 very useful, a lot of projects done. More
2 importantly, you had the production tax credits
3 that went into effect. And you can see sort of
4 the sawtooth projection of wind development here
5 when production tax credits expire, wind
6 projects stop. The support for those projects
7 was absolutely needed. That same circumstance
8 exists today for renewable natural gas.

9 A comprehensive list of the Federal Tax
10 Credit grants available for RNG today, we spent
11 a lot of time looking at this, and here is that
12 list. Okay, you've heard that earlier. We get
13 no help from the Federal Government for these
14 projects. All right, that's not entirely true
15 because we actually do get what was referred to
16 earlier, we do get for transportation purposes
17 RINS which, as you know, do have significant
18 value, but the problem with that today is the
19 pricing is volatile, it's not always at these
20 high levels, and more importantly, it's very
21 difficult to get long term Off-Take Agreements
22 because the Renewable Fuel Standard, on which
23 those are based, has been challenged, it has an
24 uncertain future, so lining these things up from
25 a financing perspective and a financial

1 engineering perspective has been problematic.

2 All right, Access to Market Impediments
3 for RNG. I'm going to go through these quickly.
4 We've talked about the high interconnection
5 costs, let me give you some examples just to
6 highlight the difference of what has been
7 experienced by my colleague to my left here in
8 the real world for interconnection costs, so
9 more renewable costs to interconnect the
10 pipelines through their projects. In 2007,
11 \$82,546; in 2008, \$70,816; in 2013, \$272,170.
12 Now, in California, for a lot of the reasons
13 that Jim Lucas had alerted to in his
14 presentation, currently the pipeline
15 interconnection cost quoted are somewhere
16 between \$1.5 million and \$3 million, that's a
17 pretty dramatic difference. That's one of the
18 big impediments as alluded to, I guess, by the
19 WebEx question also, it is a very significant
20 hurdle to cross if you don't have large
21 economies of scale.

22 All right, we've talked about the Rule
23 30 minimum heating value of 990 Btus, I've
24 alluded to the fact that because of the fact we
25 get air, for instance, on landfill projects with

1 nitrogen, very difficult to meet that standard
2 unless there is blending allowed. Mandated
3 continuous or frequent monitoring can cause
4 cost. Prohibition restriction on blending,
5 which sometimes is needed in other places to
6 meet things, is also a negative dollar or
7 prohibitive type regulation.

8 There have been some suggestions to
9 restrict volume of RNG that may be introduced
10 into California pipeline. When you start having
11 to spend 100 percent of your capital, but only
12 get a portion of your revenue, or you can only
13 operate a portion of the time, again, that
14 interferes with the financial engineering of
15 these projects.

16 Limited injection of RNG only in a
17 transmission pipelines, which is one of the
18 other things that has been suggested, also can
19 be problematic both for distance and sometimes
20 for cost.

21 Okay, I'm going to give you a menu and,
22 again, please accept this as a menu, there is
23 not unanimity of use, even among our own group
24 about whether all or some of these should be
25 adopted, but in the spirit of what we were asked

1 by the staff of the Energy Commission to give a
2 full, if you will, arsenal of tools from when
3 they could evaluate and select, we intended to
4 include everything here. So these are basically
5 approaches from a policy and regulatory
6 perspective that have worked to encourage
7 renewable energy in other areas.

8 Okay, the first is have the pipeline
9 companies basically pay for the cost of
10 interconnection, that takes at least the cost
11 from the developer's perspective out of it and
12 put it in the utility rate base. Same thing for
13 acquiring pipeline easements, they have the
14 power of condemnation; the private developer
15 does not. Again, put it in the utility rate
16 base. What's the justification for that? Well,
17 in California we have had a tremendous
18 development in the wind and solar industries,
19 and there are some hidden costs in that, some of
20 which have to do with the building of
21 transmission lines, which is getting access to
22 take the power that's generated in remote areas
23 and bring it to where the power in the low bases
24 are. Those are costs that have occasionally
25 been paid for by the Utilities and go into the

1 Ratepayer base. If a similar thing were done
2 for RNG, that would allow the projects to be
3 developed and it would spread the cost; sort of
4 a further justification of that are the
5 developers for these type of projects, in
6 landfills in particular, pay a significant
7 amount of the operations and maintenance costs
8 for collecting this type of fuel. Well, that
9 would tend, to the extent that that's taken off
10 of the basically the income statement of the
11 people owning the landfills, that would tend to
12 reduce solid waste disposal fees, and there is a
13 not an exact, but a reasonable proximity of the
14 Ratepayers on the gas side and the people who
15 pay for trash pick-up. So there is some
16 justification for that type of a regulatory
17 approach.

18 The rest of these, I'm going to just
19 note here that these are being considered in the
20 CPUC hearings, they are being considered and
21 have been considered, and we think very
22 effectively, in the ARB, and OEHHA proceedings
23 in which we participated, so I'm just going to
24 list them again in just the interest of being
25 complete. The RNG industry sort of

1 recommendation is for heating value, the most
2 common heating value spec that we face outside
3 the State of California is 950 Btus per standard
4 cubic feet, and that compares, of course, to
5 what we talked about in Rule 30 earlier.

6 Blending. This has been allowed in
7 other RNG projects, it is a technique to allow
8 gas to meet a heating value specification, to
9 meet concerns with WOBBE interchangeability, all
10 the other things that the pipeline companies
11 worry about for their customer base.

12 Monitoring. We have actually
13 participated in the CARB and OEHHA process, we
14 know what the recommendations are, and we feel
15 that those recommendations are something that
16 our industry should be able to meet in terms of
17 the type of constituents and the frequency; it
18 wasn't a perfect solution from our perspective,
19 but it's certainly one that we think we can live
20 with.

21 The volume restrictions I've talked
22 about earlier, we prefer that there not be
23 volume restrictions on this, we do understand
24 what some of the issues may be, but it is an
25 impediment to getting these projects done.

1 Renewable Natural Gas Standard. This
2 is one that sometimes gets some emotional hot
3 buttons. In the electric power world, a
4 Renewable Portfolio Standard for electric power
5 has been incredibly effective for encouraging
6 renewable electric power projects. Were
7 something similar adopted here, we think it
8 would have the same effect, which would entail
9 higher prices, but we don't think it necessarily
10 would be needed if some of these other standards
11 are adopted to encourage RNG in California. RNG
12 is a grid support for intermittent renewables.
13 This alludes to what I talked about earlier,
14 there has to be grid support for wind and solar
15 intermittent resources. We feel if there were a
16 requirement that a portion of that fueling came
17 from renewable natural gas produced in-state,
18 that would serve the purposes of the RNG
19 industry and be complimentary to what we think
20 are very good intermittent resources in wind and
21 solar.

22 Feed-in-Tariffs Providing Higher Price
23 for RNG. This becomes a very well-used
24 technique for providing needed support to close
25 the gap that I illustrated earlier in terms of

1 pricing. It's used successfully in the power
2 industry. Again, to the extent that they're
3 imposed on the common carrier pipelines, they
4 would be allowed in the rate base as they have
5 been in the electric power industry. And then
6 we would say, to the extent to which that
7 pipeline gas were, for instance, delivered to a
8 utility to satisfy an RPS requirement, or were
9 delivered to a fuel user to satisfy a Low Carbon
10 Fuel Standard requirement, that the feed-in-
11 tariff would not be something that would be
12 mandated.

13 Allow In-State Transportation of RNG by
14 Displacement. This basically doesn't -- it
15 reduces the cost and basically aligns this
16 program with how FERC treats the transportation
17 of natural gas.

18 Solutions to Increase Positive Dollars
19 for Transportation Fuel. One would be to
20 require RNG for State and Municipal CNG and LNG
21 Vehicles, and we think there will be, because of
22 the compelling economic driver with the price of
23 natural gas at \$4.00 a million, and if you look
24 at the comparable price of delivered liquid
25 fuels, it's in probably the \$20.00 range.

1 There's going to be a significant movement in
2 California both for emissions, as well as for
3 just sheer economics to move towards CNG. We
4 think the state could do a lot by mandating that
5 their vehicles procure a portion of the CNG LNG
6 fuel requirements from RNG.

7 Transportation of RNG. Again, by
8 displacement -- same policy reasons as before.

9 All right, what kind of economic
10 incentives work? Transferable Tax Credits. And
11 I'll let Frank talk a little bit about this
12 because he was very creative in funding his
13 project by use of some tax credits in this. If
14 we had transferable California tax credits that
15 were made available for this, they could be
16 either a percentage of the value of the capital
17 for the facility, or a value of the energy sold
18 for a period of time. Again, very very
19 effective techniques. The transferability of
20 the credits allows a developer that doesn't have
21 a big tax appetite to basically take advantage
22 of the economic value of these credits.

23 Grants. That's free money; that always
24 works. Very successful program for wind right
25 now, the 1603 grants, which are no longer

1 available. Again, these were only available for
2 electric power projects. RNG projects did not
3 acquire -- even if that gas ultimately went to
4 produce RNG, we could never get a tax opinion
5 saying that that qualified for the 1603 grant,
6 that would have been very helpful. That was a
7 successful program, something comparable to that
8 could be done by the State.

9 Carbon Capture Credit. We would love
10 to see a minimum Cap-and-Trade pricing,
11 transferable and tradable credit for carbon
12 capture. We're going to have to exclude some of
13 those credits perhaps from the environmental
14 attributes that have to be transferred to an
15 obligated utility if there's going to be an
16 incremental value to that. I know there's some
17 dispute as to whether that should be allowed,
18 but, again, a suggestion, any potential policy
19 thing to add value to these projects. You have
20 to coordinate, then, the carbon capture credits
21 also with the Low Carbon Fuel Standard credits,
22 again, policy things that are available.

23 Sales Tax Exemptions. Okay? This kind
24 of concept has been allowed in the wind
25 industry, same thing for real and personal

1 property tax. I'm not going to go into too much
2 detail here, but to the extent that these can be
3 applied, they're very valuable. There are a
4 number of other states that have adopted these
5 types of exemptions.

6 Financing Assistance. This is another
7 area that the State can be very helpful in, in
8 terms of supporting these projects. A state
9 guarantee of debt -- this type of approach has
10 been used before, provide a guarantee of debt,
11 sometimes it's up to 90 percent of a project
12 value provided that a project can support a
13 minimum \$1.2:\$1.0 debt coverage ratio.

14 Provide Preferential Tax Exempt Bond
15 Cap Allocation. Tax exempt bonds have been used
16 to finance these projects. We have used it in
17 other states and Frank creatively has used it
18 for his project.

19 Authorize and Provide Preferential Tax
20 Exempt Bond Cap Application. When you look at
21 the two of these together, it tends to support
22 project financing which is critically needed to
23 get the kinds of returns on equity dollars that
24 are needed for these types of projects.

25 All right, this is a little bit my own

1 rant, but there is a definite need to
2 synchronize the air emission regulations with
3 the renewable energy objectives in the State of
4 California. RNG processing technologies have an
5 extremely low emission profile. You're
6 basically turning off a flare processing the gas
7 and putting it in a pipeline, they are very low
8 from an emission perspective. Raw gas is
9 collected and not combusted.

10 All right, always categorize -- and,
11 Tim Tutt from SMUD, we agree with your comment -
12 - always categorize RNG as a zero emission fuel.
13 It has been regarded that way by DOE, it's been
14 regarded that way by the Climate Action Reserve,
15 but in the mandatory reporting requirements that
16 CARB has adopted, they provided some limitations
17 to try incent-only new projects, and so they
18 treat it as a zero emission fuel, but it's
19 limited by sometimes when a contract was signed,
20 or it may be limited after a date by incremental
21 production, we don't think that's good state
22 policy, this is a very low emitting fuel. We
23 think for in-state production, it should always
24 be regarded as a zero emission fuel and what
25 happens if you don't? Well, if you don't, the

1 utilities are obligated parties on emission
2 basis, or any other party buying this, and if
3 they have to go buy offsets, guess whose hide
4 they take that out of? The RNG developers. So
5 at the end of the day, it's taking dollars off
6 the table from these projects, we pay the price,
7 and that's a huge negative dollar impact for
8 these projects and a disincentive for them to
9 happen.

10 This is one -- we need to get straight
11 kind of the emission guidelines for projects in
12 the State of California. Most of the projects -
13 - almost all of the projects that have been done
14 in the state today are electric power projects.
15 All the ones done on landfills are very small
16 generator sizes, they're not efficient, and they
17 have higher emissions than huge 500 or 1,000
18 megawatt projects that have the economies of
19 scale to put very expensive tail end clean-up
20 on.

21 The old regulations used to allow you
22 to offset the emissions that were for flare when
23 you were turning it off to produce electric
24 power, you generated renewable electric power
25 and that was a good thing. Today, emission

1 requirements have been cranked down to a point
2 where the emissions from an onsite generator
3 have to be lower than a flare. So the policy
4 today is California would rather see you flare
5 the gas than produce renewable electric power
6 and offset fossil fuel generation somewhere
7 else. That makes no sense to me and I don't
8 think it's good policy, and I would really like
9 the Energy Commission and whoever else needs to
10 look at that to coordinate policies on that, you
11 know, it's the battle of clean air and renewable
12 energy.

13 Today there are going to be a lot of
14 landfill gas projects that are going to be shut
15 down because they will not invest the
16 substantial capital required to meet those
17 objectives, and many of those landfills are not
18 going to be large enough to do RNG projects on,
19 so we're just going to flare gas. I don't think
20 that's a good thing.

21 All right, sort of in closing, I would
22 like to indicate that the development of an RNG
23 project is really a very delicate numbers game.
24 It usually only works at larger landfills and
25 wastewater treatment plants due to the fixed

1 costs in development and O&M. You have to meet
2 the secret formula that I talked about. And
3 it's absolutely essential that you not engage in
4 fuzzy math as the positive dollars and negative
5 dollars. Okay, so what is fuzzy math? Here it
6 is. That's it, guys. Thanks.

7 MR. MARISCAL: Thank you. Paul, did
8 you have anything to add to that?

9 MR. MORROW: I'll be happy to take
10 questions later.

11 MR. MARISCAL: Okay. All right. Next
12 we have Frank Mazanec -- please correct me if I
13 said that wrong -- from Biofuels Energy; they
14 operate the Point Loma Wastewater Treatment
15 Plant.

16 MR. MAZANEC: Good morning. And thank
17 you for the opportunity to present a project
18 perspective in contrast to maybe some of the
19 global view that you've already heard.

20 Just a brief discussion of the Point
21 Loma Wastewater Treatment facility which is in
22 San Diego; it is 175 million gallons a day, I
23 believe it's the third largest in the state, so
24 it falls into that particular category. The
25 facility itself, you see GUF, it's actually

1 producing about 5 megawatts, the City of San
2 Diego is using about half of the gas that's
3 produced, the other half was being flared, you
4 see gas flares, you see three of those up there,
5 it was that incremental 50 percent of the gas
6 that was being produced that we secured from the
7 City of San Diego on a competitive basis. I
8 might add, we ended up adding a fourth flare in
9 that scenario. And one of the points I want to
10 bring out in terms of areas, when we're
11 operating this plant, those flares are all shut
12 off, so we're saving a significant amount of
13 criteria pollutants, SO_x and NO_x, and PM10s,
14 etc. I'm just adding, we get no credit for
15 that, so when people are looking to buy offsets,
16 originally you thought we might be able to sell
17 the offsets because we're saving criteria
18 pollutants, we are unable to do that, and the
19 reason we were unable to do that is because it
20 wasn't of a long term nature. That's a
21 potential area that hasn't been mentioned that
22 was disappointing.

23 The project itself is the proposed BUDG
24 site, that's Beneficial Use of Digester Gas
25 Project. We are processing about 1.1 million

1 standard cubic feet a day.

2 The only thing I wanted to highlight
3 here is the schedule itself. We actually
4 started to try to secure the gas in 2007 and we
5 began in January 2012 operating the plant, so
6 we've been operating, started operation about 18
7 months ago, to give you some idea how long it
8 takes to actually put one of these projects
9 together. The financing itself was completed in
10 November of 2010, and if there's one point --
11 there's a lot of technical focus at the Energy
12 Commission and this proceeding in general, I'd
13 venture to say that half of the challenge at
14 least is the financial engineering perspective,
15 and I don't think it's given as much credit and
16 importance in terms of really bringing these
17 projects to fruition -- it is as much financing
18 as it is the technical elements of being able to
19 make the various specs.

20 The balance of this -- I didn't want to
21 address much of the financing, but I just
22 highlight that it involves a variety, this
23 particular project -- and I'll actually give you
24 a feel for the numbers as we go -- we had the
25 1603 Grants, we had what's called the Self-

1 Generation Incentive Program Grants, we had very
2 unique New Market Tax Credit Grants, which you
3 may not have heard of, we put those into play,
4 we had the only long term debt on its facility
5 was approximately \$12.5 million of California
6 Pollution Control Financing Authority Bonds, and
7 we actually secured through a competitive
8 process in that five-year period a sales tax
9 exemption.

10 This is a look at the site itself, it
11 was rendering -- I'll show you an actual picture
12 after construction -- it's about half an acre
13 that this facility is on, and particularly what
14 I wanted to highlight, it's a little bit
15 difficult to do, but in the lower left-hand
16 corner you'll see a gray building, so running
17 from the BUDG site is about 1,200 feet, okay?
18 So if you remember Jim's presentation in terms
19 of interconnect costs and the difficulty, we
20 went through the exact same process that Jim
21 laid out in terms of all the various proceedings
22 and it almost doesn't get any better than what
23 we ended up with, we had 1,200 feet of a 4-inch
24 line, and there was no upgrades required to the
25 balance of the system itself.

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1 The only reason I included this picture
2 from another view is, if you could see the front
3 wall, that area that's fenced in, that's where
4 the SDG&E monitoring equipment is, so about a
5 third or a quarter of the site is for monitoring
6 equipment.

7 A little bit about the structure of
8 the project itself in terms of putting it
9 together may be in the uniqueness of it. We
10 secured, as I mentioned before, a contract with
11 the City of San Diego for the biogas, it's a 10-
12 year agreement that was a competitive process.
13 And in the course of doing that, of course, we
14 have to meet SDG&E's Rule 30 as it presently
15 exists for pipeline injection standards. We
16 nominate the gas that is injected to the
17 University of California at San Diego and to the
18 City of San Diego Water Reclamation facility to
19 a 2.8 megawatt and a 1.4 megawatt power plant,
20 this is all part of the project. The project
21 isn't only the injection facility, if you would,
22 but it's also energy generation. We have a 300
23 KW fuel cell at the Point Loma facility for
24 purposes of meeting the parasitic energy load at
25 the site. So we're producing about 4.5

1 megawatts, so we're effectively sending the gas
2 to each one of these sites to generate
3 electricity. This project was on a composite
4 basis and I'm trying to give you some number
5 perspective -- \$45 million in total,
6 approximately. Of that \$45 million,
7 approximately \$12.5 million is for the injection
8 facility, the rest is generation. And I want to
9 get into a little bit the \$12.5 million because
10 I know that's the focus here. We have a 10-year
11 Power Purchase Agreement with both the
12 University of California at San Diego and the
13 City on the South Bay Water Reclamation
14 facility.

15 This is a simplified process flow
16 diagram. The incoming methane in contrast to a
17 landfill which might get up to 55 percent, but
18 you may see it as low as 45, and I know this
19 says 59, but we're actually seeing like 62
20 percent, there is sulfur decompressed and cooled
21 and there's sulfur treatment. The heart of this
22 particular system, if you would, in terms of
23 removal is an Air Liquide system and, for
24 information purposes, about 12 percent of the
25 Btus that come into the system actually go to a

1 separate flare, it's not economic, if you would,
2 to continue to re-circulate that, so we get
3 about 88 percent of the Btus that are treated
4 come out as an end product.

5 You can see activated carbon polishing
6 vessels. One of the biggest issues in trying to
7 put this project together is meeting Rule 30
8 when this project was put together because how
9 do you -- you cannot find someone to guarantee
10 -- it's very very difficult to get an
11 engineering firm or someone else to guarantee.
12 Now, the waste companies might be able to put
13 their balance sheet and assume that, but a
14 smaller company like ours, trying to put project
15 financing together, you're looking for a
16 guarantee that you're going to be able to meet
17 Rule 30, or the new rules as it may be very
18 difficult to do. These polishing vessels
19 actually got us there. We were never able to
20 secure, although we received guarantee on most
21 of the constituents of the gas removal, we
22 weren't able to receive a guarantee on all of
23 them. It was the introduction of the polishing
24 vessels that provided the extra comfort, also
25 the accommodation for additional polishing

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1 vessels. So if you continued to have
2 difficulties in the removal process, you could
3 add actually more of these polishing vessels on
4 at maybe half a million or three hundred
5 thousand, to help improve with many of the
6 constituents. We don't have a nitrogen issue at
7 the site.

8 This is -- I actually intended to walk
9 you through, it's a little bit difficult from
10 here at the desk, this is a picture of the
11 actual facility itself, the BUDG. The two tanks
12 on the left, one furthest in the back is the
13 sulfur treat vessel, the other tank is a surge
14 equalization vessel as I'm moving from left to
15 right. The next box, if you would, is the
16 filter compressor, the series of pipes after
17 that, that's the Air Liquide system, the larger
18 platform in the back behind the rectangular
19 square, those are the polishing vessels that I
20 referred to. And in front of that is the SDG&E
21 monitoring equipment.

22 I mentioned Rule 30 and this might be
23 old hat, but I've got to tell you one of the
24 first questions when I heard this whole
25 proceeding was going on -- again, I'm not as

1 involved in the regulatory process, can't afford
2 to be -- why are we going through all of this
3 when we already have a Rule 30 that's in
4 existence for the injection of gas? I deal a
5 lot with landfill gas, so I certainly know it's
6 more difficult, but this is what we were
7 utilizing and this is what we're meeting. I
8 included in red what our sort of average actual
9 results are. A 98 percent methane requirement,
10 again, in contrast to landfills that may be 50
11 percent, we have 62 percent. We've been able to
12 achieve 98.1 percent methane on an actual basis.
13 We had a propane injection system as back-up,
14 this was a very big concern because if you don't
15 need it, in the WOBBE index, they'll shut you
16 down. So we included propane to be able to
17 inject it if it was needed; we haven't used a
18 lick of propane since we started operation, not
19 one Btu of propane. And you can see oxygen,
20 we're in a .1 versus .2, and carbon dioxide, for
21 example, is 3 percent and Rule 30, and we're at
22 a half of 1 percent; the inert is a 4, and at
23 combined, we're at about 1.8. So we're really
24 not -- we really have not had difficulties.
25 There's one exception I do want to bring up, I

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1 thought you might be interested, this is the
2 equipment sort of spec'd by SDG&E, if you would,
3 that we monitor continuously -- Moisture & CO2
4 Analyzer, O2 Analyzer, Gas Chromatograph, Sulfur
5 Chromatograph, and H2S Monitoring. We also have
6 Flow Measurement, Temperature Pressure, and even
7 the Heat Content, and that's actually taken
8 every few minutes, so we get this remotely --
9 you see the information on a continuous basis.

10 Since operation, we only had one time
11 where we were actually shut down and,
12 ironically, I say "shut down", we were on
13 notice, it was for moisture. So you get these
14 curveballs and we exceeded the seven pounds, and
15 the reason we did in those polishing vessels,
16 the carbon in the installation process actually
17 absorbed moisture, so when we came out of the
18 Air Liquide, it was bone dry, there was
19 absolutely no moisture in it, we put it into the
20 polishing vessels, and we exceeded the 7 pounds.
21 So we actually had to introduce some silica gel
22 which removed that moisture, and we lost about a
23 week in that whole process. And that's been our
24 own blip.

25 Now, in addition to what's being

1 monitored continuously, on a quarterly basis
2 we're being tested and that frequency will
3 reduce, depending, and in those quarterly tests
4 Siloxane, heavy metals, biological, vinyl
5 chloride, those are all reviewed as part of the
6 periodic testing.

7 I feel in a lot of ways I should be
8 mentioning the Siloxane because, in putting the
9 project together, there was actually a
10 discussion of continuous Siloxane monitoring,
11 and the angst that that caused in terms of being
12 able to put the project together, was very very
13 significant if the consequence of that --
14 because the market at the time was non-detect,
15 so how do you meet a non-detect on a continuous
16 basis? That has been removed, it's picked on a
17 quarterly basis, but that almost had the
18 possibility of literally threatening the entire
19 project just because of that particular
20 requirement, so I share that with you in terms
21 of the difficulties and the significance of it.

22 I thought it might be interesting to
23 see the fuel cell projects where the biogas
24 goes, that's the 1.4 megawatt fuel cell at South
25 Bay, City of San Diego facility, we own and

1 operate that; and at the University of
2 California at San Diego, the 2.8 megawatt fuel
3 cell. So we have renewable biogas producing
4 renewable energy.

5 I guess I won't spend a lot of time on
6 this, this is very project specific and I think
7 you might be interested in the next chart more,
8 but these are some of the issues that we
9 actually -- these are more design issues and
10 internal, of a little less, probably, concern to
11 you. But the variability of the digester gas in
12 establishing plant capacity, we didn't do the
13 best job we possibly could there; there are
14 swings, this isn't a constant production of gas.
15 And to give you an idea of the significance of
16 that, let's just say you're right at plant
17 capacity, 1.1 million, or 800 standard cubic
18 feet a minute, and you get a little more gas?
19 Well, what happens? Those flares that the city
20 has come on, but their turndown ratio is such
21 that they come on at 200 standard cubic feet a
22 minute, so we get a big drop in our gas
23 production because a little more gas was
24 provided. So the interface with the existing
25 sites at the flare becomes really quite an

1 issue.

2 I'm going to talk a little bit about
3 the interconnect and give you some perspective
4 because it is important. So who is responsible
5 for the installation of the gas interconnect?
6 And I'm going to share with you -- we elected to
7 do it ourselves because when the utility
8 presented us with their estimate of over \$1
9 million, and that might sound small relative to
10 the numbers you heard this morning, I'm used to
11 the out-of-state numbers, I thought that was
12 very very high; so retrospectively, we made a
13 mistake, we did it ourselves, and I'll show you
14 why that turned out to be a mistake. And
15 forgive me, I use SDG&E and Sempra sometimes
16 interchangeably and not necessarily correct, but
17 the utility oversaw the specs for all of the
18 equipment, and so we had to meet the design, we
19 passed the design through them, we were the
20 implementer, the designer, the implementer.

21 One of the other points is where you
22 actually extract that gas at the wastewater
23 treatment plant is important because it has a
24 lot to do -- remember, the wastewater treatment
25 plant is first and foremost a waste treatment

1 plant and the pressures, those dome pressures,
2 are very very important to them, it's created a
3 lot of issues I won't get into the details of,
4 but it's important.

5 Some of the challenges. And here are
6 some of the specifics on the interconnect that I
7 wanted to share with you. Originally when we
8 solicited and went through the entire project,
9 SDG&E/Sempra quoted an interconnect cost of
10 \$1.08 million. The gas facility itself, the gas
11 cleanup facility, is approximately \$8 million.
12 So the difference we had locked up on a fixed
13 price basis. The actual interconnect cost came
14 in at \$1.99 million, so that's like having a
15 remodel at your house for \$35,000 and having it
16 come in at \$70,000. So think of what that does
17 when you're trying to finance the plant or
18 getting a mortgage. So one of the other
19 concepts, it's great if the utility can pick up
20 these expenses for the interconnect and they can
21 be rate-based, but if that isn't feasible, if
22 something could be done where this is a numbers
23 certain, okay, to some degree even if it's a
24 quote, because the uncertainty involved in this
25 interconnect is almost unacceptable, okay? It's

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1 very very difficult to put a project financing
2 together when you have these unknown numbers
3 despite the best efforts of the utility -- the
4 utility is neutral -- if the costs turn out to
5 be more, you bear the consequence of it.

6 There's another thing that hasn't been
7 discussed, the requirements for a Btu District.
8 When you think about it, the Btu value of this
9 gas that gets injected is less than natural gas;
10 well, when the residential customers get your
11 gas, your gas is based on flow, so if they're
12 getting the same flow, but they're getting a
13 lesser Btu, they're not getting a fair shake.
14 So the utility comes in and establishes
15 districts within the utility, and they bill by
16 the average Btu value in each one of these
17 areas. So depending on how significant you are,
18 and we were significant to Point Loma, they have
19 to establish a new Btu district, so they
20 appropriately charge those particular customers.
21 This is all at our expense, right? Now, I just
22 have to tell you, we've been operating now for
23 18 months, the Btu District is not complete,
24 okay? And on the scale of things, by the way,
25 this is relatively insignificant, it's maybe

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1 \$100,000, but it's \$100,000 that's hanging out
2 there that's our expense, so that's another area
3 that it would be -- and, in fact, for a while --
4 let me just take that further -- if you can't
5 establish a Btu District, you might not actually
6 be able to put the gas into the pipeline. The
7 utility was wonderful, but that isn't talked
8 about very much, but it's very concerning from a
9 development perspective.

10 I think this has been mentioned in
11 spades, the challenge today, of course, is
12 meeting the natural gas prices. This facility
13 you're talking about in a range of \$8.50 a
14 million, to be able to produce this biogas when
15 you're competing with a \$4.00 commodity price.
16 I venture to say, we would not have been able to
17 put this project together if we didn't combine
18 it with the energy generation components of the
19 project. So while this might have been a \$12
20 million project, remember, we wrapped it around
21 a \$45 million energy project; to some degree, it
22 was subsidized, if you would, by the energy
23 components of the project because -- and I
24 didn't mention it specifically -- we received
25 over \$30 million in total grants of the \$45

1 million in grants, the combination of SGIP
2 Grants for the fuel cells and Investment Tax
3 Credits and New Market Tax Credits, so this
4 project probably would not come to be today with
5 the reduction in the availability of the funds
6 and monies that are available that enabled us to
7 put it together in that particular fashion.

8 Again, as was mentioned earlier,
9 there's no long term -- when you move into the
10 transportation component, there's no long term
11 market for the RINs today, but you can't fund
12 them for 10 years, and they could disappear a
13 year or two from now.

14 Some little side notes: we have not
15 been able to secure renewable energy credits as
16 a result of the regulatory process for the last
17 two years. This project, in my mind, is exactly
18 what the State is trying to do, I believe that's
19 the case -- use biogas, produce renewable energy
20 -- this project does not qualify for renewable
21 energy credits during the last two RECs, the
22 last two years. To be honest with you, it just
23 blows my mind the way I can't understand, but
24 that is the reality of that.

25 Furthermore, as a result, as was

1 mentioned earlier -- and I say "RECs," Bucket 1
2 RECs where there's some money involved. Also,
3 the issue with the biogas created a lot and the
4 Renewable Handbook and all of the issues in
5 terms of bringing it into being, so we did not
6 materialize as many of the attributes, if you
7 would, the RECs and the biogas incentives that
8 we were expecting to get.

9 I mentioned the impact on operation of
10 continuous Siloxane monitoring; I didn't see
11 that mentioned earlier today, I didn't hear CARB
12 mentioned the word "Siloxane," I may have missed
13 that, okay, and I'd like to hear that, I guess,
14 is the best way to say that because this is a
15 major issue, it could stop everything in the
16 tracks from the development perspective. Now,
17 we are being tested for it and we actually are
18 meeting the marks, but being able to meet a non-
19 detect and a guarantee is pretty difficult to
20 do, obviously.

21 One of the other concerns in this whole
22 marketplace is what happens as a result of the
23 present process relative to the BUDG. We're
24 operating this plant, we've been very concerned
25 about meeting Rule 30, what's the consequence of

1 not only the Regulations that are being
2 discussed today on us, or future developers
3 putting a project together, but what happens
4 when the Regulations change? What if the
5 Regulations are such that we couldn't meet it
6 because the Regulations change on a going
7 forward basis? Are you grandfathered? You
8 realize just that item alone which it could sit
9 out there and just say, "Oh, it's just a
10 matter...", "that could stop the project itself
11 because the financiers go, "I'm not going to take
12 the regulatory risk that a year from now you're
13 going to come along and change the rules that we
14 might not be able to meet. We don't know what
15 the rule change is going to be." That's not
16 addressed in any way, shape or form, there's no
17 guarantees provided. How do you make that type
18 of step up to that? And, again, we would not
19 have been able to do this, in my opinion, on a
20 standalone basis. The way we got around a lot
21 of these concerns and are bringing up is the
22 wrapping around of the balance of the project
23 itself.

24 That's the next one, was the changing
25 of the biogas, and I mentioned the guarantee and

1 the reduction of all of the incentives. This is
2 well known and addressed, you know, ultimate
3 uses for renewable biogas.

4 I guess I just want to put a little
5 meat on the transportation fuel because we're in
6 the process of the developing of landfill gas
7 project up in the State of Washington and we had
8 that targeted as a CNG project, we've been
9 working on this for about four years, we're
10 developing a 5 megawatt energy project right
11 now. With all of the rule changes on biogas,
12 our intent was to bring the biogas down to
13 California and build construction, jobs in the
14 State of California. But now you can't bring
15 the CNG down in the State of California and get
16 all of the advantages that you previously could.
17 So the regulatory -- and I know I'm not being
18 very specific here, but the net result is you
19 can't bring that gas down here and have the
20 incentives. So California has lost out, in my
21 opinion, on the labor market and the jobs that
22 otherwise could be brought in with this
23 renewable fuel, as a result of some of the
24 regulatory changes.

25 Specifics on transportation fuel: these

1 are roughly at \$1.70 a diesel gallon equivalent,
2 right, right now diesel is what? Four bucks?
3 So you could gut the price in half, that's
4 equivalent to almost \$13.00 an MMBtu. So if you
5 could develop one of these facilities at \$8.50
6 to generate electricity, and you could secure
7 revenue of \$13.00, which is a half of the
8 transportation cost, you've got a real win. The
9 problem is you're faced with competing against
10 natural gas at \$5.00, so on a standalone basis
11 you get a tremendous improvement in the
12 marketplace for renewable gas, but you're
13 competing with natural gas and it's sort of that
14 -- it stunts the growth.

15 Certainly the "Directed biogas" could
16 be used in new energy generation facilities, you
17 could sell the biogas in the Investor Owned
18 Utilities to meet RPS goals, and then you could
19 sell it effectively to commercial and industrial
20 customers, although I think there are issues
21 there also in regards to whether you would be
22 eligible for the RECs or not, but these are
23 certainly alternate uses for the biogas. And
24 hopefully that served as an overview of this
25 particular project. Thank you.

1 MR. MARISCAL: Thank you, Frank. So
2 before I open it up to panel comments on each
3 other's presentations, I want to go ahead and
4 ask Chuck White to come up; I guess he has to
5 leave early for -- okay, I would like to open it
6 up to the panelists to see if they have any
7 comments on each other's presentations,
8 questions for each other. Okay, well, I have a
9 couple of questions.

10 MR. MAZANEC: Excuse me.

11 MR. MARISCAL: Go ahead. Sorry, Frank.

12 MR. MAZANEC: I had a question for Jim,
13 or maybe the group. How does the existing Rule
14 30 interface, if you would, with the present
15 process? Will it be eliminated and replaced to
16 buy? I know the Utilities are working together.
17 What does that look like on a going forward
18 basis?

19 MR. LUCAS: My understanding, come
20 year-end when the Commission adopts new
21 Standards, that will be the standard for all the
22 Utilities, so that would replace the existing
23 Rule 30.

24 MR. MAZANEC: Has anyone done a
25 comparison to what CARB has put out as the

1 guideline compared to Rule 30 in terms of any
2 constituents being more stringent, or less
3 stringent, or what does that comparison look
4 like? And furthermore, if there is a difference
5 between the two, that example that I just gave,
6 what would be the impact on an existing
7 facility?

8 MR. MARISCAL: Please.

9 MR. MILKEY: Well, Paul Milkey, ARB,
10 it's a little bit of an apples to oranges right
11 now because the Rule 30 looks at both health and
12 pipeline integrity issues, and the portion that
13 we made recommendations on is only addressing
14 public health. We certainly were looking at
15 Rule 30 to take a look at some of the examples
16 of Standards that were out there already. I
17 could say it's a little bit hard to compare
18 because some of the Standards in Rule 30 apply
19 to very broad classes, whereas ours is
20 particular compounds, whereas Rule 30 will have
21 things like a VOC Standard, or a halogenated, so
22 it's kind of difficult to compare right now.
23 But certainly as we work with the CPUC, as they
24 go through their process, we'll be looking at
25 any opportunities to coordinate the public

1 health standards with the pipeline integrity
2 standards that they'll be working on. So right
3 now it's a little bit early to say.

4 MR. MARISCAL: Any other questions or
5 comments from the panel? I do have one question
6 from Zhi Chin in our Research & Development
7 Division. She asks: "What is the anticipated
8 cost of pipeline biomethane in terms of dollars
9 per million Btu in your analysis? And what
10 price in terms of dollars per million Btu will
11 the Utilities buy the pipeline biomethane?" I
12 think that was answered or address in some of
13 the presentations, but if you'd just --

14 MR. WILLIAMS: Yeah, I had some cost
15 numbers illustrative in ours, but I think it's
16 difficult to answer because, if it's an in-
17 state, there are no numbers I can give you; I
18 can give you roughly that the out-of-state
19 purchase price of the utilities, and this was
20 for RPS Standards, were in the double-digit
21 range for the purchase price of gas, and that
22 compared very favorably using the very low heat
23 rates and the combined cycles that fuel was used
24 in, to convert it to a very low cost renewable
25 energy kilowatt hour. So for those purposes, it

1 was very cost-effective to pay a higher price in
2 support of the RNG project and still get a lower
3 cost renewable kilowatt hour than some of the
4 alternative technologies. So I hope that
5 addresses that question.

6 MR. MARISCAL: Jim.

7 MR. LUCAS: Something else that we've
8 done, we've looked at when you inject biomethane
9 into the pipeline and say it's used at a RPS
10 certified facility, you know, what market price
11 of biomethane makes it competitive with the
12 likes of wind and solar? And so based on a
13 market price of \$9.00 to \$12.00 per MMBtu, that
14 can produce renewable power at a RPS certified
15 power plant that's very competitive with wind
16 and solar. It's between, you know, \$90.00 and
17 \$110.00 per megawatt hour.

18 MR. MARISCAL: Okay, any other comments
19 and questions? Comments from the --

20 MR. MAZANEC: I just tried to be
21 specific. It was about \$8.50 a million to
22 produce. There's some question in regards to
23 sort of the overhead costs and how you spread
24 those, but that's the ballpark, so from there
25 using the secret formula, you certainly have to

1 get above that for starters.

2 MR. MARISCAL: Thank you. I have one
3 question. I believe this was in Evan's
4 presentation that there is a restriction on
5 blending biogas with natural gas prior to
6 injecting it into the pipeline system, and I was
7 wondering if I heard that right, or if you could
8 elaborate and explain maybe why there is that
9 restriction.

10 MR. WILLIAMS: Well, there is no
11 current -- there's current discussions, let me
12 put it that way, in connection with these
13 proceedings about that. Blending has been
14 allowed out of state because there are no in-
15 state projects for most of these RNGs. with
16 probably the sole exception being Frank's
17 project. But it is a technique, for instance,
18 he mentioned propane. We have used that as a
19 higher Btu fuel to get to the -- and it's
20 primarily the heating value spec that gets to be
21 of concern. And understand, from the
22 developer's perspective meeting any one of these
23 specs is really a difficult concern, as Frank
24 alluded to, because it isn't a reduction in your
25 revenue -- you get shut out of the pipeline and

1 it's an elimination of your revenue. So the
2 consequences are rather Draconian if you cannot
3 meet this, and certainly the finance community
4 is well aware of it. And if there are not
5 sufficient margins of safety to meet these
6 projects, they can be nice in theory, but in the
7 real world they'll be impossible to get
8 financing for, and so that's why there is such a
9 heightened concern on the part of those of us
10 who have actually had to do this elsewhere to
11 make sure that the standards that get developed
12 clearly, you know, we absolutely appreciate the
13 health and safety and pipeline integrity
14 concerns. I submit that the Utilities in the
15 other part of the country have equal degrees of
16 concerns about their customers, employees, etc.,
17 and we've been able to achieve those, the
18 Standards are not quite as difficult here.
19 Admittedly, some of the costs, as we've talked
20 about, may be higher and that's why we suggested
21 some potential approaches to address those
22 differentials in cost.

23 MR. MARISCAL: Jim or Bill, do you have
24 anything to add?

25 MR. LUCAS: As far as blending, when

1 you look at it from what I mentioned earlier
2 where, you know, throughout the year you're
3 going to have different conditions based on
4 demand on the system. So in the summer, you may
5 have little demand on the system and you're
6 injecting biomethane into the pipeline, and
7 those customers will receive a high percent of
8 biomethane. So that's why, you know, that
9 blending doesn't work from an operational
10 perspective when it comes to injecting pipeline
11 quality gas.

12 MR. RAYMUNDO: I would add that it's
13 the way you define blending. If you define
14 blending as trying to meet the pipeline quality
15 requirement, then that would not be acceptable
16 to us; however, if you're doing blending to meet
17 your Btu requirement, I don't think we have much
18 say on what you do to meet that Btu requirement.
19 But the main reason for the Btu is that we're
20 required to make sure that the Btu level of that
21 Btu area is within plus or minus 5 Btu, and
22 that's because of the safety of the equipment,
23 the furnaces and appliances.

24 MR. MARISCAL: Okay, thank you. Paul,
25 I think you had your hand raised?

1 MR. MORROW: Yeah. We do blending in
2 Texas and we do it at times to make Btu spec,
3 sometimes as much as a third of the gas we
4 blend. We just have a contract to buy some gas
5 and sell it back, we blend it. My experience
6 coming from a -- I'm a registered professional
7 Chemical Engineer and I've built facilities for
8 natural gas, conventional natural gas, and so
9 biogas kind of has this label that is different
10 because it's bio, but it's not different;
11 natural gas comes out of the ground in all kinds
12 of different qualities all over the United
13 States, and it has to be treated, and it's all
14 stuck in a line and it all gets blended to some
15 kind of uniform spec at some point. But when
16 gas comes out of the ground, it's a different
17 thing. So the way we came to this business was,
18 instead of having a conception fit that we were
19 asked to build a biogas plant, we just said,
20 "give us a gas analysis and we'll see what's in
21 it." So we did that, we figured out how to --
22 and we actually built our facilities out of
23 usually used natural gas processing equipment,
24 and it's not rocket science, and it's
25 conventional materials and equipment that make

1 it all work. And as far as our place blending,
2 the pipeline we're dealing with there isn't so
3 concerned that we're blending biogas, all they
4 care about is did you meet the spec when it went
5 back into the pipeline. So when we're dealing
6 with pipelines, our goal as a company is to try
7 to just say, "Don't hold us to a spec, same spec
8 you hold everybody else to," and we'll get it
9 there.

10 MR. MARISCAL: Thank you.

11 MR. LUCAS: There is blending
12 downstream of the interconnection and there's
13 blending upstream, and so basically, you know,
14 SoCalGas, we want the gas that goes into our
15 system to meet Rule 30, and what's done
16 upstream, if you blend, that's where you need to
17 meet the 990, as long as it meets the spec at
18 our interconnection, that's what matters.

19 MR. MARISCAL: Okay, great. I'm going
20 to open it up to the floor for questions and
21 we'll start with Chuck White from Waste
22 Management. And then afterwards, we'll just
23 have people queue up to the mic if you have any
24 questions or comments for the panel.

25 MR. WHITE: I hope that includes

1 comments because I don't really have any
2 questions of this esteemed panel, but I do have
3 some comments. In large part, in further
4 substantiation of what many of the comments were
5 made, I'd just like to share Waste Management's
6 experience on trying to develop biomethane,
7 which is in large part similar to what many of
8 the commenters have been up here.

9 I'm going to focus primarily on in-
10 state development of biomethane resources by
11 Waste Management, but I do want to mention that
12 we are providing out-of-state biomethane, we do
13 have one project from Ohio Landfill that is
14 currently providing landfill gas Btu credits
15 into Publicly Owned Utilities in California, and
16 we've been delivering that since late 2011. We
17 believe that AB 2196 will allow us to continue
18 to provide that gas because we were within the
19 timeframe specified in that bill, but that is
20 actually a medium Btu gas that we're putting
21 into a storage facility that is highly blended
22 with other sources of natural gas to result in
23 us to deliver the credits to -- the gas to the
24 POU's in California.

25 So it is possible in other places of

1 the country to blend even medium Btu gas into
2 delivery, depending on the circumstances. And
3 so I just wanted to make that point to let you
4 know that it is done elsewhere, it's widely
5 done, and as Mr. Morrow said, it's basically on
6 what are the standards that you ultimately
7 deliver it to, and all gas sources are going to
8 be subject to that.

9 With respect to in-state sources, Waste
10 Management has primarily developed landfill gas
11 to electricity onsite at our landfills. We have
12 10 gas producing landfills in California, about
13 five of which have beneficial use, either
14 turbines or internal combustion engines, or in
15 one case we actually produce a renewable fuel.
16 But we're running into real problems with those
17 engines primarily from Air Pollution Control
18 Standards by -- we're largely in the South
19 Coast, the San Joaquin and Bay Area Air
20 Districts for these plants, and these are really
21 the three Air Districts that have the most
22 restrictive standards. And we are worried about
23 what we're going to be doing in the next few
24 years, we're looking at possibly building a
25 couple additional plants, but the economics are

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1 very tenuous.

2 The prices that we're getting for
3 electricity produced from biomethane at
4 landfills used to be about \$.10 a kilowatt hour,
5 and it's gone down to a little over \$.08 per
6 kilowatt hour, at the same time that we have
7 increasing costs. So it's really a challenge
8 and, in fact, this idea that we're going to be
9 shutting down some of these beneficial uses of
10 biomethane in California in the near future is
11 really truly a reality; in fact, we have one
12 facility in Southern California for which the
13 engines are now shut down because we're
14 evaluating whether it makes sense to do ongoing
15 repairs to those engines given the fact that we
16 have declining revenues and increasing costs,
17 and the impending Rule 1110.2 by the South Coast
18 Air District that will come into effect in the
19 next two years. So there is some real
20 possibility there.

21 What are our options if we can't
22 generate electricity onsite? We can put
23 landfill gas into a pipeline, but you can't do
24 that yet in California, so that option seems to
25 be off the table. We can produce LNG onsite,

1 which we are doing in one case, but we really
2 for the most part believe that we're going to be
3 using CNG for fueling our trucks in the future,
4 so at the time we built that plant, we thought
5 possibly otherwise. The other option would be
6 to use onsite use of the gas, but for the most
7 part, in most cases our trucks and other
8 vehicles are at another location than where
9 we're generating the gas, so that doesn't make
10 sense. So we're really stuck and it's ironic
11 that, as we face AB 32 and greenhouse gas
12 requirements, that we're actually looking at
13 returning to flaring at many of our biomethane
14 resources, rather than use them beneficially
15 because of a whole variety of factors.

16 Let me talk really briefly about
17 landfill gas to pipeline. We are hoping that AB
18 1900 will open the door in not all cases, but in
19 those few cases where we are within about a mile
20 or so, or less, of a pipeline; but we're really
21 concerned about where the whole process is
22 going. We don't frankly understand why the
23 IOUs, primarily PG&E and Sempra, there really
24 has a been a focus on their gas pipeline people,
25 to their credit, I mean, they really want to

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1 protect their gas pipelines, and I totally
2 understand that, but I haven't really heard, at
3 least from PG&E's side of the house, the people
4 that need to produce renewable energy or reduce
5 greenhouse gas emissions from combined cycle
6 natural gas plants that either they own, or have
7 contracted with other providers; don't they want
8 this biomethane to reduce their reliance on high
9 carbon fossil fuels to overall reduce the carbon
10 intensity of the electricity they produce, which
11 is surely going to be a requirement under AB 32?
12 And I've just been surprised at the lack of
13 desire on the part of the Utilities to want to
14 get access, which I don't frankly understand,
15 and I'd like to know more about that. The POUs,
16 on the other hand, saw this opportunity early on
17 and, even though you couldn't get in-state
18 pipeline gas, they contracted with out-of-state
19 providers, such as Waste Management that I
20 mentioned before. It just seems to me there
21 ought to be a demand for displacing fossil
22 natural gas and combined cycle natural gas
23 plants in California to generate electricity,
24 but there doesn't seem to be a vocal outcry for
25 that. Maybe I'm missing it somewhere, but I

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1 haven't seen it yet.

2 The other concern I have about 1900 is
3 the fact that the way the bill was written, it
4 charges the CPUC to come up with standards for
5 those constituents that are in biomethane, that
6 are not in natural gas. But it doesn't really
7 provide an objective comparison of the
8 constituents that are found in natural gas with
9 the constituents that are found in renewable
10 natural gas, or biomethane. I've seen a lot of
11 data over the last few months about constituents
12 that are in natural gas that are not in
13 biomethane, but we're not focusing on those kind
14 of constituents. And I'm not a health
15 scientist, but I wish CARB and OEHHA had been a
16 little less constrained by the language of 1900
17 to be able to take an objective view at what's
18 in natural gas, an objective view what's in
19 biomethane, and making sure we're not over-
20 regulating something simply because it doesn't
21 show up in fossil natural gas, but there may be
22 other constituents in fossil natural gas that
23 are as equally of concern, and so we're
24 basically putting the screws to those
25 constituents in bio LNG where there is no

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1 similar requirement. And no one wants to put
2 natural gas under scrutiny, it's been in use for
3 a long time and people are used to it, it's just
4 worrisome that there's this heightened and ultra
5 concern about biomethane that doesn't seem to be
6 a similar kind of level of concern as applied to
7 natural gas.

8 Anyways, let me go on and talk just
9 briefly about our landfill gas to LNG plant at
10 Altamont. That plant was first conceived when
11 the price of fossil natural gas was about \$14.00
12 to \$17.00 per MMBtu. It cost \$15 million to
13 build, and we're currently producing up to
14 13,000 gallons of LNG per day. There's no
15 pipeline nearby, we have to put in trucks to
16 truck it around to our fueling facilities
17 throughout California to use this. Well, when
18 we were finished building that plant and began
19 operating, the price of natural gas had fallen
20 to \$8.00 per million Btu and, as you know, has
21 gotten down as low as \$3.00, and I think it's up
22 between \$4.00 and \$5.00 right now. So
23 additional plants really don't make sense. We
24 actually did secure a grant from the Energy
25 Commission to build a second plant. We're still

1 looking to try and figure out how to put the
2 economics to do that, that was when the price
3 was about \$8.00 per MMBtu and we thought we
4 could probably still make money with a grant,
5 but we can't make it with the price just down
6 \$4.00 or \$5.00, so we're kind of caught in a
7 holding pattern right now.

8 What we are hopeful in looking at are
9 the RIN and LCFS credits. The problem that I
10 think Evan pointed out is that they're not
11 really fungible, you can't go and secure a
12 longtime contract with a oil company that has a
13 compliance obligation under either the RFS2 or
14 the LCFS before you build a plant. You have to
15 wait until you build the plant and then see if
16 someone is willing to buy those credits
17 essentially after you've constructed it. So
18 it's really hard to use that value of RIN and
19 LCFS credit for financing these new facilities.
20 If there could be found a way to secure a long
21 term financing for an agreed upon price of these
22 LCFS and RIN credits -- in fact, we've even
23 suggested that recently to folks involved in the
24 legislative process this year, is could we use
25 some of the revenue from the Cap-and-Trade

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1 program to set up a fund that would be used to
2 purchase, make long term commitments to buy
3 contracts from people to produce RIN and LCFS
4 credits, that would go into a bank that would
5 then be resold to the oil companies that need it
6 for their compliance purposes. That way, you'd
7 have a guaranteed revenue stream as much as you
8 can figure it out of the \$4.00 to \$5.00 per
9 MMBtu for the comparable price of natural gas
10 plus the value of the RIN credits over the five
11 to 10 year capital period, and then RFS2
12 credits. So we're hopeful --

13 MR. MARISCAL: Chuck, can I get you to
14 wrap it up so we can have somebody else come up?

15 MR. WHITE: -- yeah, I'm almost done.
16 So we really need to get some certainty in RIN
17 and LCFS credits. We would urge the CEC also,
18 on some of your AB 118 grants you have
19 restrictions on how much you can generate in
20 terms of LCFS, and it's questionable about RIN
21 credits, it would be nice if we could get that
22 restriction removed or modified; I know you've
23 got a rulemaking process in the offing to try to
24 address that, but there is some concern about,
25 you know, what is the restrictions that would be

1 applied down the road to RIN and LCFS credits if
2 you're also a recipient of a AB 118 grant.

3 One other comment; we're also looking
4 at other types of biomethane projects, anaerobic
5 digestion facilities, we made some investments
6 in companies that are doing that, but the
7 problem is landfill gas right now is the low
8 hanging fruit. If you cannot make money -- or
9 POTW, really, those are the two categories -- if
10 you can't make a return on investment using POTW
11 gas or landfill gas, we don't understand how you
12 can possibly make a return on investment on
13 other types of anaerobic digestion facilities
14 unless there's other incentive programs. One
15 incentive program was possibly to put a mandate
16 on the diversion of organic waste from landfills
17 under AB 323, but that basically got stalled in
18 the Legislature last week, and so it wasn't
19 going to be up again until next year, so there
20 isn't going to be that incentive to provide a
21 separate means of managing organic waste. So I
22 guess the whole point is you really need to look
23 at all the incentive programs for all these
24 different things and see what can be put
25 together, but right now it's so challenging for

1 biomethane to really show that you can make a
2 return on investment that, frankly, investment
3 dollars just simply aren't there right now.
4 Thank you.

5 MR. MARISCAL: Thank you, Chuck. Any
6 response from the panel?

7 MR. WILLIAMS: I'd just like to say
8 that Chuck, I think, nailed it right on the head
9 for a lot of these things. It goes back to the
10 secret formula issue, and it really is
11 financing, it is making sure that you can get a
12 return of, as well as a return on your
13 investment, and I would agree that, without some
14 of these incentives that we talked about in the
15 presentations today, it's going to be very
16 difficult to achieve that.

17 MR. MARISCAL: Thank you. And just a
18 reminder, if you do not have enough time to
19 provide all your comments in verbal form, you're
20 more than welcome to submit them in writing.
21 Any other comments? Yes.

22 MR. BEST: Good morning. Kevin Best,
23 Real Energy. Great job, Evan and Frank, nothing
24 speaks louder than experience. I wanted to talk
25 about the interconnection costs again. So,

1 Frank, I think you had a million dollar budget
2 and it ended up at two, and I assume part of
3 that was the utility tax?

4 MR. MAZANEC: No.

5 MR. BEST: No? So, Jim, I mean, you
6 made it pretty clear in your three options that
7 we got to pay the utility tax in all three
8 options?

9 MR. LUCAS: No. The utility tax, I
10 mean, there is an exemption, so you have to fill
11 out the safe harbor's questionnaire and, based
12 on those questions and those answers, the
13 interconnector may be exempt from paying the
14 ITCCAs, which is that tax. But I think what
15 Frank mentioned was that, you know, they went
16 with doing their design themselves, and the
17 construction themselves, but it still requires
18 SoCalGas or SDG&E supervision, to approve the
19 plans, construction drawings and, you know, with
20 third-party engineering firms not being familiar
21 with our requirements, there's a lot of back and
22 forth. And so I'll let Frank speak more to
23 that, but --

24 MR. MAZANEC: Yeah. I wish you had
25 done that originally, but the truth of the

1 matter is nothing saying that that million
2 dollar estimate might not have been a million
3 and a half, in any event; we don't know the
4 answer to that. But in reality, we made a
5 decision to do it ourselves under the
6 supervision of SDG&E, and we doubled the price
7 of the original estimate but the time it was
8 actually completed.

9 MR. BEST: So as we put this tariff
10 together, I just wonder, Frank, if you were
11 doing this again, it seems like the right
12 answer, I mean, we've done dozens of utility
13 interconnections, the right answer is to stay
14 away from that tax like a third rail. So we
15 kind of default want to do it ourselves,
16 provided we have the right mix of people. So
17 the question would be, is that exemption easy to
18 earn? And if we were to do this again, do you
19 think there's a path that we could give them in
20 writing this tariff that would keep us away from
21 that tax?

22 MR. MAZANEC: I'd just get you in
23 trouble to give you tax advice. The only
24 comment or action that I would put on it is a
25 very very complex financial engineering business

1 arrangement to be able to check the boxes
2 appropriately. And it isn't done very easily.

3 MR. BEST: All right. Then my last
4 comment, I would just support Chuck in this
5 notion of a rolling fund. I mean, the
6 California IO (ph) bank is set up to do that,
7 it's their charter, and it just seems like the
8 right answer. Thank you very much.

9 MR. MARISCAL: Thank you.

10 MR. LUCAS: It's -- I'll add real fast
11 -- the tax isn't based on who does the design of
12 the interconnection, the tax is based on a set
13 of 10 questions that need to be answered,
14 regardless of who does the design and
15 construction work.

16 MR. THEROUX: Hello again, Michael
17 Theroux, JDMT. Jim, this is a question for you.
18 You made very clear, of course, that location,
19 location, location. Alongside of location is
20 timing, and in working with easement projects
21 and utilities projects in the past it's been
22 kind of paramount to look at the overlap of
23 timing in other projects and to reach in and to
24 plan activities according to when the dirt is
25 already going to be open. So you have a map of

1 the locations. Can you model at this point far
2 enough in advance such that you can say these
3 are the sweet spots, "we will be opening this at
4 this time, and we'll be working on these
5 sections at this time in these regions"? It
6 takes a long time, 18 to 24 months is nothing in
7 most of these projects, as Frank has certainly
8 found. So can SoCalGas, PG&E open the book
9 enough on the planning to say where the projects
10 in the future will allow a cost reduction
11 because ongoing work already has the trenches
12 open, ongoing work is already worked out, the
13 utilities, easements, questions, worked out with
14 the rail lines, perhaps, on those kinds of
15 projects; can you work to identify the sweet
16 spots of not only location, but of timing?

17 MR. LUCAS: Man, that's a tough
18 question to answer. You know, based on my
19 previous experience, I did supervise a group of
20 employees that did a franchise-related pipeline
21 replacement, and so basically, you know, we're
22 based on what the City is doing, so they want to
23 install a new storm drain, you know, they give
24 us those drawings, and we may have to alter our
25 pipeline and tear up some road. You know,

1 generally speaking, it's not going to be a huge
2 section of pipeline, so if you have to install
3 two miles of pipeline, the chances of that
4 location and that pipeline and there being a
5 franchise job in that same location are
6 extremely small. But generally most cities do
7 notify us, you know, give us some type of future
8 plans of when they may plan on repaving streets,
9 for instance. So that's something that could be
10 worked out with cities is based on when they
11 plan on doing construction and try to time that
12 with some interconnection projects if there's
13 something in place. But right now, I mean, our
14 service territory is so large that it would be
15 extremely difficult to go through and try to
16 find out sweet spots based on how many dozens of
17 cities are out there and what their future plans
18 are.

19 MR. THEROUX: Municipal certainly is
20 one major category, but in addition to that we
21 have the Federal projects on highways and such
22 where there are easements and, in particular, we
23 have the rail utilities easements, and I would
24 believe that the rail easements might be more
25 schedulable, if you will. So among all the

1 various areas that one might be able to lay out
2 a timeline, I would suggest that there are areas
3 where, indeed, it is more feasible to plan that
4 far in the future, so now you have a question of
5 matching the nexus of the most feasible timing
6 with the nexus of the locations where it can be
7 done, and perhaps identify a very short list of
8 potential project locations and timing at some
9 point in the future that you believe would be
10 the most propitious for the kinds of projects
11 that we're talking about.

12 MR. MAZANEC: Yeah, I think it's worth
13 mentioning because we're talking about timeline
14 and interconnect, I think we had the best case
15 that one could hope for, right? Short distance,
16 1,200 feet. The process that we had with the
17 utility was six months, I think, and it's been a
18 while since I went back and actually looked at
19 that. That's through the two studies and
20 effectively getting the green light and getting
21 the agreement. So I think maybe being
22 conservative and in more cases than not it would
23 be an extended period of time, but it is
24 possible if you're lucky enough to be located in
25 the right spot that it might be able to actually

1 do much better than that.

2 MR. LUCAS: Well, that 18 to 24 months
3 includes everything from first notification, to
4 having the actual interconnection up and
5 running, so it's not just the three studies,
6 it's beyond that.

7 MR. MAZANEC: Add 12 months to that six
8 months!

9 MR. MARISCAL: All right. Thank you,
10 Michael. Tim Tutt.

11 MR. TUTT: Good morning. And I'm
12 speaking in this instance not on behalf of SMUD,
13 but as a natural gas consumer in California,
14 specifically PG&E consumer. If I were a non-
15 core PG&E customer, I would be able to procure
16 some Renewable Natural Gas from one of these
17 fine gentlemen and use it in my facility; I'm
18 far from that in my house. If I were large
19 enough, I would even be able to reduce my
20 compliance obligation in the Cap-and-Trade
21 structure by doing that. But as a residential
22 customer, I don't have that option. I would
23 like that option. I would like the option of a
24 voluntary procurement of Renewable Natural Gas
25 at my house as this system gets freed up and

1 Renewable Natural Gas comes into the pipeline,
2 it seems reasonable to allow your residential
3 consumers to also reduce their carbon footprint
4 by procuring natural gas as designated for use
5 of their house. And there's going to be a
6 workshop, a Cap-and-Trade workshop, coming up
7 next week, we'll talk about natural gas
8 suppliers. It seems like we also might have an
9 interaction with your ability to meet the Cap-
10 and-Trade obligation in that circumstance.
11 Thank you.

12 MR. ADAIR: My name is Chad with SMUD
13 and I work in the Energy Trading and Contracts
14 Department. And we kind of represent a bit of
15 an interesting perspective from our group, it's
16 kind of two different perspectives, 1) we
17 procure the renewable energy that we need to
18 meet RPS, as well as some of the AB 32
19 compliance requirements that are upon us; but in
20 our group we're also responsible for asset
21 management of our natural gas assets and in my
22 group specifically.

23 So SMUD, as many of you know, we're an
24 equity owner in the PG&E backbone pipeline, so
25 we have a distinct interest in the pipeline

1 safety from a public health perspective, as well
2 as from pipeline integrity. So we have a unique
3 perspective in terms of we need this biomethane
4 to meet our aggressive renewable energy goals
5 that not only the state has mandated on us, but
6 also the SMUD Board that has put an additional
7 four percent over and above the 33 percent.

8 But we also obviously have a great
9 concern in making sure that the pipeline is
10 safe, not just the equity ownership in the PG&E
11 backbone system, but also in the 76 miles that
12 SMUD owns and operates. And from our
13 perspective, at least in my group, you know, the
14 significant challenges to procuring biomethane,
15 the one that sticks out the most is regulatory
16 certainty. As a POU, we have to know that what
17 we're purchasing is going to meet the
18 requirement on a going forward basis. We can't
19 stick our Ratepayers with a contract that is
20 then canceled by regulatory or legislative
21 issues down the road that then we're continuing
22 to pay a premium for this product.

23 Obviously, economics is also important
24 to us. You know, we heard a lot about the
25 economic aspect from the developer's perspective

1 and we can appreciate that because we're
2 basically paying for those revenues to exceed
3 expenses, and so economics are obviously
4 important to us. Now, granted it gets passed
5 onto our Ratepayers as a POU, but we have the
6 responsibility as does PG&E and the other
7 utilities, the IOUs, to make sure that we're
8 responsible with that ratepayer money. So, you
9 know, we're not going out there and being
10 irresponsible and purchasing contracts that are
11 out of the money. So economics are critically
12 important to us.

13 And I think another thing that's
14 important that has been mentioned here a couple
15 of times today is it's critical from my
16 perspective, in looking at both sides of this
17 from the renewable goals that we're trying to
18 meet, from the pipeline integrity, the health
19 and safety of our public and our Ratepayers, I
20 think it's critical that on both issues from the
21 renewable energy perspective that we don't waste
22 a renewable asset like biomethane, that we're
23 not flaring it. It's critical that we make
24 proper comparisons between natural gas and
25 biomethane so that we're not putting an undue

1 burden upon biomethane that, you know, there's
2 testing methods that have been implemented for
3 years, automatic shutoff, different things for
4 natural gas. I think it's critical that we make
5 the comparisons there between natural gas and
6 biomethane, the standards that are used, I think
7 there's a lot of data that we can look at to
8 really make quality comparisons and look at the
9 differences between the constituents of current
10 concerns in both, but it's critical that we make
11 proper comparisons between the two products so
12 that we don't put an unnecessary burden upon
13 this valuable asset and waste it. So I guess
14 just an interesting perspective from SMUD's
15 vantage point that we care about both and in the
16 same exact group, we're having to manage both
17 issues. So thank you.

18 MR. MARISCAL: Thank you. Any response
19 from the panel?

20 MR. MORROW: I was just going to say,
21 in our experience we've dealt with pipelines
22 that wanted to hold us to -- not SoCal, other
23 pipelines that we dealt with in the areas where
24 we operate in Texas, Louisiana, and Arkansas --
25 where they wanted us to test for certain

1 contaminants that we were not allowed to test
2 for in their trunk lines. In other words, it
3 was a case of "please don't find that here,
4 we'll have a problem."

5 So what's in natural gas is everything,
6 natural gas comes out of the ground, once again,
7 that I've said it before, but there's a lot of
8 natural gas that comes out of the ground and as
9 soon as you breathe it, it would kill you from
10 hydrogen sulfite. So the idea that we're
11 talking about some part per trillions and
12 billions of Siloxanes and stuff, that's really
13 not anywhere near the threat of a lot of other
14 natural gas. Now, the good news about that is
15 that apparently our empirical data says most
16 people don't die from this, you know, we found a
17 way to work around it.

18 MR. MARISCAL: Thank you. Are there
19 any other questions or comments in the room? Go
20 ahead.

21 MS. BURKE: Carol Burke from PG&E. I
22 really liked your talk. A couple of questions I
23 had, that you said you had 1,200 feet you had to
24 install to connect with SoCal? And what was the
25 size of the line that you connected with?

1 MR. MAZANEC: Four-inch. Oh, we had a
2 four-inch line, I think it went to either a six
3 -- four and it went to six.

4 MS. BURKE: What was the pressure?

5 MR. LUCAS: It hooked into SDG&E, not
6 SoCalGas, just for the record.

7 MS. BURKE: Okay.

8 MR. MAZANEC: Thank you.

9 MS. BURKE: But do you know the size
10 and pressure of that line?

11 MR. MAZANEC: I don't know.

12 MS. BURKE: You don't.

13 MR. MAZANEC: I'm sorry, I don't know.
14 I knew it was a four-inch line, that's --

15 MS. BURKE: The customers that had the
16 billing change, you had to change their Btu
17 area?

18 MR. MAZANEC: We didn't.

19 MS. BURKE: Well, I know, but that were
20 changed as a result of the introduction of your
21 gas, do you know how many were impacted?

22 MR. LUCAS: This is SDG&E.

23 MS. BURKE: Okay. And then your Btu,
24 what is it normally? Like 990 or so?

25 MR. MAZANEC: Actually, yeah, and

1 above. Actually 1,001 might have been it for
2 last year --

3 MS. BURKE: Okay, yeah, that's pretty
4 good.

5 MR. MAZANEC: -- 98.1 percent methane,
6 whatever that plays out --

7 MS. BURKE: Yeah, I sort of did a rough
8 calculation to show it would be about 900 --

9 MR. MAZANEC: But that's still less
10 than the natural gas heating value.

11 MS. BURKE: In that area?

12 MR. MAZANEC: Yes.

13 MS. BURKE: Okay. And then I also
14 noticed you compress upstream of the treatment,
15 is that you have to for the pressure -- the
16 pressure and absorption?

17 MR. MAZANEC: Yes.

18 MS. BURKE: Okay. That's it. Thank
19 you.

20 MR. MARISCAL: Are there any other
21 questions from the room? We have a few
22 questions from the Web. I'll have Otto read
23 those out.

24 MR. TANG: All right, so the first
25 question is from Jeffrey G. Grill. The question

1 is: "In response to the comment that Utilities
2 keep the gas within a range of plus or minus 5
3 Btus/scf for appliances, I would like to point
4 out that there are different Btu specifications
5 across the state. These specifications have a
6 wide range of allowable heating values ranging
7 much more than plus or minus 5 Btus/scf. But
8 this speaks to a larger issue, that inter-
9 changeability should be made uniform across each
10 of the utilities throughout the state. Without
11 this, it would be difficult for a producer to
12 know what they are getting into until after the
13 contracts are signed and producers are about to
14 begin injecting into the pipeline. For example,
15 assuming the interchangeability specification
16 used by a utility is the AGA Bulletin 36
17 switched to a specification for the flame
18 perimeters, 1) yellow tipping, 2) flashback, 3)
19 liftoff of a gas flame from a burner, the
20 calculation also compares the produced
21 gas/biogas to a standard reference gas. The
22 issues with the lack of interchangeability
23 standardization is the exact values for these
24 flame perimeters and the specific composition of
25 the reference gas is not necessarily given by

1 the utility to the producer until the plant
2 design is complete or about to inject. This
3 adds a significant uncertainty and risk to the
4 producer and allows the utility to define these
5 perimeters after the fact and non-uniformly.
6 These are hidden knobs that can be turned to
7 make biogas injection extremely difficult, if
8 not impossible. What efforts are being made to
9 eliminate this loophole?"

10 MR. RAYMUNDO: Actually, what we do is
11 we monitor -- it will be indexed, but I'll have
12 Carol Burke here, who is our Gas Quality
13 Specialist, to respond to those questions.

14 MS. BURKE: Bill misused the 5 Btu
15 difference, that's -- we use that when
16 determining whether or not we need a new Btu
17 area -- I don't know who I'm talking to -- so
18 some guy somewhere.

19 MR. MARISCAL: You're talking to the
20 Internet.

21 MS. BURKE: And so that's not our
22 interchangeability criteria, we use AJA 36, I
23 think that's what it says in our Rule 21, and
24 new things have been developed since then, and
25 we're following that, NYSEARCH did some work

1 that we've been using recently, so we use
2 whatever is the newest industry approved
3 interchangeability program. But it's not plus
4 or minus 5 Btu, that's what we use for billing
5 to ensure that customers are billed properly.

6 MR. MARISCAL: Thank you. Are there
7 any other questions from the Web? Okay, are
8 there any questions from the phone lines? The
9 phone lines are unmuted if you have any
10 questions. Hearing no questions, I'll move on.
11 All right, I'm going to allow the panel to make
12 any other final comments. No final comments?

13 Okay, I want to thank everybody for
14 attending here today, I really appreciate it.
15 Again, written comments are due 5:00 p.m., June
16 14th. Instructions are on the screen. Thank
17 you very much. Have a great afternoon.

18 (Thereupon, the Workshop was adjourned at 12:08

19 p.m.)

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